ORCA

ORCA EXPLORATION GROUP INC.

2017 ANNUAL REPORT

Orca Exploration Group Inc. is an international public company engaged in hydrocarbon exploration, development and supply of gas in Tanzania and oil appraisal and gas exploration in Italy. Orca Exploration trades on the TSXV under the trading symbols ORC.B and ORC.A.

GLOSSARY

mcf	Thousands of standard cubic feet	1P	Proven reserves
MMcf	Millions of standard cubic feet	2P	Proven and probable reserves
Bcf	Billions of standard cubic feet	3P	Proven, probable and possible reserves
Tcf	Trillions of standard cubic feet	Kwh	Kilowatt hour
MMcfd	Millions of standard cubic feet per day	MW	Megawatt
MMbtu	Millions of British thermal units	US$	US dollars
HHV	High heat value	CDN$	Canadian dollars
LHV	Low heat value	bar	Fifteen pounds pressure per square inch

Financial and Operating Highlights

(Expressed in US$000 unless indicated otherwise)	YEAR ENDED DECEMBER 31 **2017**	2016	% Change 2017 vs 2016
OPERATING			
Daily average gas delivered and sold *(MMcfd)*			
Additional Gas	**41.6**	44.5	(7)%
Industrial	**12.6**	12.5	1%
Power	**29.0**	32.0	(9)%
Average price *(US$/mcf)*			
Industrial	**7.71**	7.70	0%
Power	**3.60**	3.56	1%
Weighted average	**4.84**	4.73	2%
Operating netback *(US$/mcf)* [1]	**3.00**	3.26	(8)%
RESERVES			
Additional Gas Gross Recoverable Reserves to end of licence *(Bcf)*			
Proved	**307**	347	(12)%
Probable	**73**	58	26%
Proved plus probable	**380**	405	(6)%
Net Present Value, discounted at 10% *(US$ millions)* [2]			
Proved	**269**	313	(14)%
Proved plus probable	**326**	363	(10)%
FINANCIAL			
Revenue	**51,854**	65,885	(21)%
Net cash flows from operating activities	**48,154**	19,968	141%
per share - basic and diluted *(US$)*	**1.38**	0.57	141%
Net (loss) income	**(2,500)**	2,164	(216)%
per share - basic and diluted *(US$)*	**(0.07)**	0.06	n/m
Funds flow from operations [1]	**14,840**	31,855	(53)%
per share - basic and diluted *(US$)*	**0.43**	0.91	(53)%
Capital expenditures (excluding transfers)	**1,545**	16,924	(91)%

(Expressed in US$000 unless indicated otherwise)	AS AT DECEMBER 31 **2017**	2016	
Working capital (including cash)	**69,575**	71,989	(3)%
Cash	**122,322**	80,895	51%
Long-term loan	**58,518**	58,399	0%
Outstanding Shares *('000)*			
Class A	**1,751**	1,751	0%
Class B	**33,506**	33,106	1%
Total shares outstanding	**35,257**	34,857	1%
Weighted average Class A and Class B shares	**34,858**	34,857	0%

[1] *See MD&A – non-GAAP measures*

[2] *In accordance with the PSA the Company is able to recover income tax and consequently there is no significant difference between the NPV of reserves on a before and after tax basis.*

2017 Operating Highlights

- The Company's revenue for the year decreased by 21% to US$51.9 million from US$65.9 million in the prior year. The decrease is the result of: (i) recording revenue from TANESCO using the estimated collectability approach, (ii) lower sales volumes and; (iii) lower Cost Gas allocations which resulted in an increase in Profit Gas attributable to TPDC; this was a consequence of the decline in the cost pool with the Company having now recovered the cost of the 2015-2016 capital program. Additional Gas deliveries and sales for the year averaged 41.6 million standard cubic feet per day ("MMcfd") a decrease of 7% over 44.5 MMcfd in the prior year. The decrease in Additional Gas volumes for the year is primarily the result of reduced nominations of natural gas volumes by TANESCO. The decrease in volumes was partially offset by a 2% rise in the weighted average price for year to US$4.84/mcf from US$4.73/mcf in the prior year.
- Total proved reserves for Additional Gas decreased 12% to 307 Bcf from 347 Bcf in the prior year and total proved plus probable reserves ("2P") decreased 6% to 380 Bcf from 405 Bcf in the prior year. The decrease is a consequence of 2017 Additional Gas production of 15.2 Bcf and lower anticipated growth in Power sales to the Company. The net present value of the estimated future cash flows from the 2P reserves at a 10% discount rate ("NPV10") decreased by 10% to US$326.1 million from US$363.0 million in the previous year. The decrease is a result of the lower forecast sales to the Power sector at lower average prices. Under the terms of the PSA, the Company is required to pay Tanzanian income tax but this is recovered by the Company through the profit sharing arrangements with TPDC. Income tax has no material impact on the cash flows emanating from the PSA and accordingly there is no significant difference between the NPV of reserves on a before and after tax basis.
- The Company recorded a net loss of US$2.5 million for the year compared to a net income of US$2.2 million in the prior year. The loss for the year is due to a number of factors: (i) the decrease in revenue being partially offset by lower finance expenses; (ii) the decrease in finance expenses being the net effect of lower TANESCO debt write-offs, offsetting the IFC participatory interest; and (iii) the increase in stock based compensation in 2017.
- The Company's net cash flows from operating activities for the year increased by 141% to US$48.2 million from US$20.0 million in the prior year. The increase is primarily a consequence of the continued improved collections from TANESCO since the third quarter of 2016, which is evidenced by the US$8.4 million deferred revenue recorded on the statement of financial position.
- The Company's funds flow from operations for the year decreased by 53% to US$14.8 million from US$31.9 million in the prior year. The decrease is primarily a consequence of the fall in the Company's operating revenue due to the change in the TANESCO revenue recognition criteria together with lower sales of Additional Gas volumes, lower Cost Gas and an increase in TPDC Profit Gas entitlement. In addition, as a consequence of the lower capital expenditure during the year and improved collections from TANESCO, the IFC are entitled to participatory interest of US$3.8 million.
- Working capital decreased 3% to US$69.6 million compared to US$72.0 million as at December 31, 2016. This minor decline is a consequence of the increase in current liabilities to TPDC associated with increased collections from TANESCO, together with the increase in stock based compensation accrual following an increase in the closing share price for the year to CDN$5.00 per share from CDN$3.86 per share as at December 31, 2016.
- At December 31, 2017 the current receivable from TANESCO was US$ nil (December 31, 2016: US$5.7 million). During the year, the amounts received from TANESCO were in excess of the revenue recognized for gas sales to TANESCO resulting in a deferred revenue balance of US$8.4 million (December 31, 2016: US$ nil) after the reallocation of US$3.8 million to net field revenue during Q4 2017. The long-term trade receivable at December 31, 2017 and 2016 was US$74.4 million (provision of US$74.4 million). Since the year end, the Company has invoiced TANESCO US$6.2 million for 2018 gas deliveries and TANESCO has paid the Company US$10.0 million.
- Subsequent to December 31, 2017 the Company sold 7.9 percent of PAE PanAfrican Energy Corporation, a wholly owned subsidiary, for a net sales price of US$21.1 million based on a net enterprise value of US$265.0 million. The effective date of the transaction was January 1, 2017 and as a consequence, the purchase price was reduced by US$0.9 million to reflect the buyer's share of cash flow from the effective date of the transaction until closing. The buyer has until May 11, 2018 to acquire up to an additional 32.1 percent of the subsidiary under the same terms and conditions.

Gas Reserves

The Company's natural gas reserves as at December 31, 2017 for the period to the end of its licence in October 2026 were evaluated by independent petroleum engineering consultants in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). The independent reserves evaluation is dated March 6, 2018 with the effective date of December 31, 2017. A reserves committee of the Company reviews the qualifications and appointment of the independent reserves evaluator and reviews the procedures for providing information to the evaluators. Reserves included herein are stated on a company gross basis unless noted otherwise. All the Company's reserves are conventional natural gas reserves and are located in Tanzania. Additional reserves information required under NI 51-101 are included in Orca's reports relating to reserves data and other oil and gas information under NI 51-101, which have been filed on its profile on SEDAR at *www.sedar.com*.

On a gross Company basis there has been a 12% decrease in Songo Songo's Total Proved Additional Gas reserves to the end of the licence period, with 2% decrease on a life of field basis, with a total Additional Gas production of 15.2 Bcf during the year. There has been a 6% decrease in the Proved plus Probable Additional Gas reserves on a gross Company life of licence basis from 405.3 Bcf to 380.1 Bcf with a 3% decrease on a life of field basis.

A summary of the remaining Additional Gas reserves on a life of licence basis are presented below:

Songo Songo Additional Gas reserves to end of licence - October 2026 *(Bcf)*	**2017** **Gross** [1]	 **Net** [2]	2016 Gross	 Net
Independent reserves evaluation				
Proved producing	**295.9**	**183.3**	343.6	209.6
Proved developed non-producing	**10.7**	**6.0**	3.8	2.2
Proved undeveloped	**–**	**–**	–	–
Total proved (1P)	**306.6**	**189.3**	347.4	211.8
Probable	**73.5**	**54.4**	57.9	47.4
Total proved and probable (2P)	**380.1**	**243.7**	405.3	259.2

(1) *Gross equals the gross reserves that are available for the Company after estimating the effect of the TPDC back in (see below).*

(2) *Net equals the economic allocation of the Gross reserves to the Company as determined in accordance with the PSA.*

The estimated net present values of the Songo Songo reserves before and after tax on a life of licence basis are as follows:

	2017			2016		
US$'millions	***5%***	***10%***	***15%***	*5%*	*10%*	*15%*
Proved producing	**327.6**	**262.6**	**215.3**	404.6	312.1	247.3
Proved developed non producing	**10.1**	**6.9**	**4.8**	2.2	1.0	0.3
Proved undeveloped	**–**	**–**	**–**	–	–	–
Total proved (1P)	**337.7**	**269.5**	**220.1**	406.8	313.1	247.6
Probable	**71.0**	**56.6**	**46.3**	63.7	49.9	40.3
Total proved and probable (2P)	**408.7**	**326.1**	**266.4**	470.5	363.0	287.9

There has been a 10% decrease in the 2P present value at a 10% discount basis from US$363.0 million to US$326.1 million on a life of licence basis. The decrease is a result of the lower forecast sales to the Power sector at lower average prices.

Gas Reserves

For the reserves certification as at December 31, 2017, the McDaniel Report has assumed that TPDC will exercise its right to 'back in' to any additional new field development plans for Songo Songo and consequently will receive a 20% increase in the profit share for the future production emanating from the Songo Songo North well, SSN-1. McDaniel has taken the view that this 'back in' right should be treated as a TPDC working interest and therefore the Gross reserves have been adjusted for the volumes of Additional Gas that are allocated to TPDC for their working interest share.

For the purpose of calculating the Gross Additional Gas reserves, McDaniel has assumed in its 2P case that 96 Bcf (2016: 111 Bcf) or an average of 14.6 Bcf per annum will be required to meet the demands of the Protected Gas users from January 1, 2018 to July 31, 2024. During 2017 the Protected Gas users consumed 14.8 Bcf.

A summary of the remaining Additional Gas reserves on a life of field basis are presented below.

	1P Additional Gas price *US$/mcf*	1P Gross Additional Gas volumes *MMcfd*	2P Additional Gas price *US$/mcf*	2P Gross Additional Gas volumes *MMcfd*
2018	4.05	61.9	3.94	73.1
2019	3.94	78.1	4.00	91.8
2020	3.95	88.4	4.01	103.0
2021	4.12	89.1	4.07	119.0
2022	4.27	89.8	4.22	120.1
2023	4.39	90.6	4.35	121.3
2024	4.35	108.1	4.36	139.3
2025	4.29	131.7	4.33	163.0
2026	4.37	131.7	4.41	163.0

A summary of the remaining Additional Gas reserves on a life of field basis are presented below.

	2017		2016	
Songo Songo Additional Gas reserves to end of field life *(Bcf)*	**Gross** [(1)]	**Net** [(2)]	Gross	Net
Independent reserves evaluation				
Proved producing	**579.7**	**362.6**	595.0	365.9
Proved developed non-producing	**47.1**	**26.5**	47.0	26.5
Proved undeveloped	**–**	**–**	–	–
Total proved (1P)	**626.8**	**389.1**	642.0	392.4
Probable	**109.7**	**75.7**	117.5	84.9
Total proved and probable (2P)	**736.5**	**464.8**	759.5	477.3

(1) Gross equals the gross reserves that are available for the Company after estimating the effect of the TPDC back in (see below).
(2) Net equals the economic allocation of the gross reserves to the Company as determined in accordance with the PSA.

ORCA EXPLORATION GROUP INC.

2017 MANAGEMENT'S DISCUSSION & ANALYSIS

Management's Discussion & Analysis

THIS MD&A OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS SHOULD BE IN CONJUNCTION WITH THE AUDITED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES FOR THE YEAR ENDED DECEMBER 31, 2017. THIS MD&A IS BASED ON THE INFORMATION AVAILABLE ON APRIL 13, 2018.

FORWARD LOOKING STATEMENTS

This management's discussion and analysis ("MD&A") contains forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation. More particularly, this MD&A contains, without limitation, forward-looking statements pertaining to the following: the Company's expectations regarding supply and demand of natural gas; anticipated power sector revenues; potential impact of Tanzanian Petroleum Development Corporation ("TPDC") future back-in rights on the economic terms of the Production Sharing Agreement ("PSA"); ability to meet all conditions under the International Finance Corporation ("IFC") financing agreement; the Company's estimated spending for the planned Development Program for 2018 and 2019, which includes the tie-in of wells to processing facilities, well workovers and installation of a refrigeration unit on the Songas processing facility, to ensure gas production can continue at the requisite specification and volumes, and enable production through the National Natural Gas Infrastructure Project ("NNGIP") which includes two gas processing facilities and pipelines supplying gas from the Mtwara Region of Tanzania and Songo Songo Island to Dar es Salaam; the potential impact of the Petroleum Act, 2015 ("Petroleum Act") and the Finance Act, 2016 on the Company's business in Tanzania; the potential impact of the recently enacted Natural Wealth and Resources (Permanent Sovereignty) Act, 2017, the Natural Wealth and Resources Contracts (Review and Re-Negotiation of Unconscionable Terms) Act, 2017 and The Written Laws (Miscellaneous Amendments) Act, 2017; the Company's belief that the parties to the unsigned Amended and Restated Gas Agreement ("ARGA") will continue to conduct themselves in accordance with the ARGA until a new Gas Sales and Purchase Agreement ("GSPA") is signed; the Company's expectation that, despite the Re-Rating Agreement of the gas processing plant owned by Songas Limited ("Songas") having expired, the Songas gas processing plant production volumes will not be restricted; the anticipated effect of the recently approved Second Additional Gas Plan ("AGP2") on the Company's available volumes of Additional Gas for sale; additional Songo Songo field developments contemplated in connection with AGP2; the current and potential production capacity of the Songo Songo field; the Company's ability to access new markets; the Company's ability to produce additional volumes; the Company's ability to access additional processing and transportation capacity; the status of ongoing negotiations with TPDC; the potential increase in sales volumes associated with new gas sales agreements; the Company's ability to locate and bring online additional supply in the future; the Company's expectation that it can expand and maintain the deliverability of gas volumes in excess of the existing Songas infrastructure; the forward-looking statements under "Contractual Obligations and Committed Capital Investment"; the Company's expectation that it will not have a shortfall during the term of the Protected Gas delivery obligation to July 2024; and the Company's expectations in respect of its appeals on the decisions of the Tax Revenue Appeals Tribunal and other statements under "Contingencies – Taxation". In addition, statements relating to "reserves" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be produced profitably in the future. The recovery and reserve estimates of the Company's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Although management believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, access to resources and infrastructure, performance or achievement since such expectations are inherently subject to significant business, economic, operational, competitive, political and social uncertainties and contingencies.

These forward-looking statements involve substantial known and unknown risks and uncertainties, certain of which are beyond the Company's control, and many factors could cause the Company's actual results to differ materially from those expressed or implied in any forward-looking statements made by the Company, including, but not limited to: failure to receive payments from the Tanzanian Electric Supply Company Limited ("TANESCO"); risk that the potential financing solutions to resolve the TANESCO arrears are not implemented by the Tanzanian government; risk that additional gas volumes available to the NNGIP from third parties will replace all or a portion of the volumes currently nominated by TANESCO under the Portfolio Gas Sales Agreement ("PGSA") until additional gas-fired power generation is brought on-stream to consume all of the Company's available gas production; risk that the Development Program is not completed as planned and the actual cost to complete the Development

Program exceeds the Company's estimates; risk that the remaining well workovers under the Development Program are unsuccessful or determined to be unfeasible; risk of a lack of access to Songas processing and transportation facilities; risk that the Company may be unable to complete additional field development to support the Songo Songo production profile through the life of the licence; risk that the Company may be unable to develop additional supply or increase production values; risks associated with the Company's ability to complete sales of Additional Gas; potential negative effect on the Company's rights under the PSA and other agreements relating to its business in Tanzania as a result of the recently approved Petroleum Act and recently enacted legislation, as well as the risk that such legislation will create additional costs and time connected with the Company's business in Tanzania; risks regarding the uncertainty around evolution of Tanzanian legislation; risk that, without extending or replacing the Re-Rating Agreement, the gas being processed through the Songas gas processing plant may be reduced back to its original capacity, resulting in a material reduction in the Company's sales volumes of Additional Gas; risk that the Company will not fully recover Songas' share of capital expenditures associated with the workovers of wells SS-5 and SS-9; risk that the Company will not be successful in appealing claims made by the Tanzanian Revenue Authority ("TRA") and may be required to pay additional taxes and penalties; the impact of general economic conditions in the areas in which the Company operates; civil unrest; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations, impact of new local content regulations and variances in how they are interpreted and enforced; increased competition; the lack of availability of qualified personnel or management; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility; competition for, among other things, capital, drilling equipment and skilled personnel; failure to obtain required equipment for drilling; delays in drilling plans; failure to obtain expected results from drilling of wells; effect of changes to the PSA on the Company; changes in laws; imprecision in reserve estimates; the production and growth potential of the Company's assets; obtaining required approvals of regulatory authorities; risks associated with negotiating with foreign governments; inability to satisfy debt obligations and conditions; failure to successfully negotiate agreements; and risk that the Company will not be able to fulfil its contractual obligations. In addition, there are risks and uncertainties associated with oil and gas operations, therefore the Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by these forward-looking statements will transpire or occur, or if any of them do so, what benefits the Company will derive therefrom. Readers are cautioned that the foregoing list of factors is not exhaustive.

Such forward-looking statements are based on certain assumptions made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments, as well as other factors the Company believes are appropriate in the circumstances, including, but not limited to, that the Company will be able to negotiate Additional Gas sales contracts in relation to the recently approved AGP2; the ability of the Company to complete additional developments and increase its production capacity; that the Company and TPDC will agree to the terms of a Gas Sales Agreement; the actual costs to complete the Development Program are in line with estimates; that there will continue to be no restrictions on the movement of cash from Mauritius or Tanzania; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company will have adequate funding to continue operations; that the Company will successfully negotiate agreements; receipt of required regulatory approvals; the ability of the Company to increase production at a consistent rate; infrastructure capacity; commodity prices will not further deteriorate significantly; the ability of the Company to obtain equipment and services in a timely manner to carry out exploration, development and exploitation activities; future capital expenditures; availability of skilled labour; timing and amount of capital expenditures; uninterrupted access to infrastructure; the impact of increasing competition; conditions in general economic and financial markets; effects of regulation by governmental agencies; that the Company's appeal of various tax assessments will be successful; that the enactment of the Petroleum Act and new legislation in Tanzania will not impair the Company's rights under the PSA to develop and market natural gas in Tanzania; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; and other matters.

The forward-looking statements contained in this MD&A are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Management's Discussion & Analysis

NON-GAAP MEASURES

THE COMPANY EVALUATES ITS PERFORMANCE USING A NUMBER OF NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) MEASURES. THESE NON-GAAP MEASURES ARE NOT STANDARDIZED AND THEREFORE MAY NOT BE COMPARABLE TO SIMILAR MEASUREMENTS OF OTHER ENTITIES.

- FUNDS FLOW FROM OPERATIONS REPRESENTS NET CASH FLOWS FROM OPERATING ACTVITIES LESS INTEREST EXPENSE AND BEFORE CHANGES IN NON-CASH WORKING CAPITAL (see FUNDS FLOW FROM OPERATIONS). THIS IS A PERFORMANCE MEASURE THAT MANAGEMENT BELIEVES REPRESENTS THE COMPANY'S ABILITY TO GENERATE SUFFICIENT CASH FLOW TO FUND CAPITAL EXPENDITURES AND/OR SERVICE DEBT.
- OPERATING NETBACKS REPRESENT THE PROFIT MARGIN ASSOCIATED WITH THE PRODUCTION AND SALE OF ADDITIONAL GAS AND IS CALCULATED AS REVENUES LESS PROCESSING AND TRANSPORTATION TARIFFS, GOVERNMENT PARASTATAL'S REVENUE SHARE, OPERATING AND DISTRIBUTION COSTS FOR ONE THOUSAND STANDARD CUBIC FEET OF ADDITIONAL GAS. THIS IS A KEY MEASURE AS IT DEMONSTRATES THE PROFIT GENERATED FROM EACH UNIT OF PRODUCTION, AND IS WIDELY USED BY THE INVESTMENT COMMUNITY.
- FUNDS FLOW FROM OPERATIONS PER SHARE IS CALCULATED ON THE BASIS OF THE FUNDS FLOW FROM OPERATIONS DIVIDED BY THE WEIGHTED AVERAGE NUMBER OF SHARES.
- NET CASH FLOWS FROM OPERATING ACTIVITIES PER SHARE IS CALCULATED AS NET CASH FLOWS FROM OPERATING ACTIVITIES DIVIDED BY THE WEIGHTED AVERAGE NUMBER OF SHARES.

ADDITIONAL INFORMATION REGARDING ORCA EXPLORATION IS AVAILABLE UNDER THE COMPANY'S PROFILE ON SEDAR AT *www.sedar.com*.

NATURE OF OPERATIONS

The Company's principal operating asset is its interest in the PSA with TPDC and the Government of Tanzania in the United Republic of Tanzania. This PSA covers the production and marketing of certain gas from the Songo Songo Block offshore Tanzania.

The PSA defines the gas produced from the Songo Songo field as "Protected Gas" and "Additional Gas". The Protected Gas is owned by TPDC and is sold under a 20-year gas agreement (until July 31, 2024) to Songas. Songas is the owner of the infrastructure that enables the gas to be treated and delivered to Dar es Salaam, which includes a gas processing plant on Songo Songo Island.

Songas utilizes the Protected Gas as feedstock for its gas turbine electricity generators at Ubungo and for onward sale to customers. The Company receives no revenue for the Protected Gas delivered to Songas and operates the original wells and gas processing plant on a 'no gain no loss' basis.

Under the PSA, the Company has the right to produce and market all gas in the Songo Songo Block in excess of the Protected Gas requirements ("Additional Gas") until the PSA expires in October 2026.

TANESCO is a parastatal organization which is wholly-owned by the Government of Tanzania, with oversight by the Ministry for Energy ("ME"). TANESCO is responsible for the generation, transmission and distribution of electricity throughout Tanzania. Natural gas has become an integral component of TANESCO's power generation fuel mix as a more reliable source of supply over seasonal hydro power and a more cost effective alternative to liquid fuels. The Company currently supplies gas directly to TANESCO by way of the PGSA and indirectly through the supply of Protected Gas and Additional Gas to Songas, which in turn generates and sells power to TANESCO. TANESCO is the Company's largest customer and the gas supplied by the Company to Songas and TANESCO today fires approximately 30% of the electrical power generated in Tanzania and 41% of the gas utilized for power generation in the country.

In addition to gas supplied to Songas and TANESCO for the generation of power, the Company has developed and supplies an industrial gas market in the Dar es Salaam area consisting of some 38 industrial customers.

Consolidation

The companies which are 100% owned that are being consolidated are:

Company	Incorporated
Orca Exploration Group Inc.	British Virgin Islands
Orca Exploration Italy Inc.	British Virgin Islands
Orca Exploration Italy Onshore Inc.	British Virgin Islands
PAE PanAfrican Energy Corporation	Mauritius
PanAfrican Energy Tanzania Limited ("PAET")	Jersey
Orca Exploration UK Services Limited	United Kingdom

PRINCIPAL TERMS OF THE TANZANIAN PSA AND RELATED AGREEMENTS

The principal terms of the Songo Songo PSA and related agreements are as follows:

Obligations and restrictions

(a) The PSA covers the two licences in which the Songo Songo field is located ("Discovery Blocks"). The Proven Section is essentially the area covered by the Songo Songo field within the Discovery Blocks. The Company has the right to conduct petroleum operations, market and sell all Additional Gas produced and share the net revenue with TPDC for a term of 25 years, expiring in October 2026.

(b) No sale of Additional Gas may be made from the Discovery Blocks, if in the Company's reasonable judgment such sales would jeopardize the supply of Protected Gas. Any Additional Gas contracts entered into are subject to interruption. Songas has the right to request that the Company and TPDC obtain security reasonably acceptable to Songas prior to making any sales of Additional Gas from the Discovery Block to secure the Company's and TPDC's obligations in respect of Insufficiency (see (c) below).

(c) "Insufficiency" occurs if there is insufficient gas from the Discovery Blocks to supply the Protected Gas requirements or if the gas is so expensive to develop that its cost exceeds the market price of alternative fuels at Ubungo.

Where there have been third party sales of Additional Gas by the Company and TPDC from the Discovery Blocks prior to the occurrence of the Insufficiency, the Company and TPDC shall be jointly liable for the Insufficiency and shall satisfy its related liability by either replacing the Indemnified Volume (as defined in (e) below) at the Protected Gas price with natural gas from other sources; or by paying money damages equal to the difference between: (a) the market price for a quantity of alternative fuel that is appropriate for the five gas turbine electricity generators at Ubungo without significant modification together with the costs of any modification; and (b) the sum of the price for such volume of Protected Gas (at US$0.55/MMbtu escalated) and the amount of transportation revenues previously credited by Songas to the state electricity utility, TANESCO, for the gas volumes.

(e) The "Indemnified Volume" means the lesser of the total volume of Additional Gas sales supplied from the Discovery Blocks prior to an Insufficiency and the Insufficiency Volume. "Insufficiency Volume" means the volume of natural gas determined by multiplying the average of the annual Protected Gas volumes for the three years prior to the Insufficiency by 110% and multiplied by the number of remaining years (initial term of 20 years) of the power purchase agreement entered into between Songas and TANESCO in relation to the five gas turbine electricity generators at Ubungo from the date of the Insufficiency.

Access and development of infrastructure

(f) The Company is able to utilize the Songas infrastructure including the gas processing plant and main pipeline to Dar es Salaam. Access to the pipeline and gas processing plant is open and can be utilized by any third party who wishes to process or transport gas.

Songas is not required to incur capital costs with respect to additional processing and transportation facilities unless the construction and operation of the facilities are, in the reasonable opinion of Songas, financially viable. If Songas is unable to finance such facilities, Songas shall permit the seller of the gas to construct the facilities at its expense, provided that, the facilities are designed, engineered and constructed in accordance with good pipeline and oilfield practices.

Revenue sharing terms and taxation

(g) (75% of the gross field revenues, less processing and pipeline tariffs and direct sales taxes in any year ("field net revenue") can be used to recover past costs incurred. Costs recovered out of field net revenue are termed "Cost Gas".

The Company pays and recovers costs of exploring, developing and operating the Additional Gas with two exceptions: (i) TPDC may recover reasonable market and market research costs as defined under the PSA; and (ii) TPDC has the right to elect to participate in the drilling of at least one well for Additional Gas in the Discovery Blocks for which there is a development program as detailed in an Additional Gas plan ("Additional Gas Plan") as submitted to the ME, subject to TPDC being able to elect to participate in a development program only once and TPDC having to pay a proportion of the costs of such development program by committing to pay between 5% and 20% of the total costs ("Specified Proportion"). If TPDC does not notify the Company within 90 days of notice from the Company that the ME has approved the Additional Gas Plan, then TPDC is deemed not to have elected. If TPDC elects to participate, then it will be entitled to a ratable proportion of the Cost Gas and their profit share percentage increases by the Specified Proportion for that development program.

To date, TPDC has neither elected to back in within the prescribed notice period nor contributed any costs associated with backing in, and accordingly the Company has determined that to date there has been no working interest earned by TPDC. For the purpose of the reserves certification as at December 31, 2017, it was assumed that TPDC will 'back-in' for 20% for all future new drilling activities as determined by the current submitted Additional Gas Plan and this is reflected in the Company's net reserve position.

(h) In 2009 the energy regulator, Energy and Water Utility Regulatory Authority ("EWURA"), issued an order that saw the introduction of a flat rate tariff of US$0.59/mcf from January 1, 2010. The Company's long-term gas price to the Power sector as set out in the unsigned ARGA and the PGSA is based on the price of gas at the wellhead. As a consequence, the Company is not impacted by the changes to the tariff paid to Songas or other operators in respect of sales to the Power sector. As at the date of this report, the ARGA remains an initialed agreement only and the parties are not in agreement with all the terms in the ARGA, however the parties are conducting themselves in terms of pricing as though the ARGA is in force. The Company and Songas are currently reviewing the terms of a new sales agreement.

In 2011 the Company signed a re-rating agreement with TANESCO, TPDC and Songas (the "Re-Rating Agreement") which evidenced an increase to the gas processing capacity of the Songas facilities to a maximum of 110 MMcfd (the pipeline and pressure requirements at the Ubungo power plant restrict the infrastructure capacity to a maximum of 102 MMcfd). Under the terms of the Re-Rating Agreement, the Company paid additional compensation of US$0.30/mcf for sales between 70 MMcfd and 90 MMcfd and US$0.40/mcf for volumes above 90 MMcfd by issuing credit notes to TANESCO. This was in addition to the tariff of US$0.59/mcf payable to Songas as set by the energy regulator, EWURA.

In May 2016 the Company notified TANESCO and Songas that the additional compensation for sales over 70 MMcfd would no longer be paid effective June 2016. The additional compensation was always intended to be temporary in nature until the expansion of the Songas infrastructure, at which time Songas would apply to EWURA to obtain approval of a new tariff for the processing of volumes over 70 MMcfd. The PGSA provides for passing on to TANESCO any tariff to be charged to the Company in the event that a new tariff is approved.

The parties are seeking to resolve the status of the re-rating agreement. The processing capacity at the Songas facilities remains unaltered and is fully utilized by the company. Without a new agreement, there are no assurances that Songas will continue to allow the gas plant to operate above 70 MMcfd. Under the terms of this agreement, the Company agreed to indemnify Songas for damage to its facilities caused by the re-rating, up to a maximum of US$15 million, but only to the extent that this was not already covered by indemnities from TANESCO's or Songas' insurance policies. The cost of maintaining the wells and flowlines is split between the Protected Gas and Additional Gas users in proportion to the volume of their respective sales. The cost of operating the gas processing plant and the pipeline to Dar es Salaam is covered through the payment of the pipeline tariff.

(i) Profits on sales from the Proven Section ("Profit Gas") are shared between TPDC and the Company, the proportion of which is dependent on the average daily volumes of Additional Gas sold or cumulative production.

The Company receives a higher share of the field net revenue after cost recovery, based on the higher of the cumulative production or the average daily sales. The Profit Gas share available to the Company is a minimum of 25% and a maximum of 55%.

Average daily sales of Additional Gas	**Cumulative sales of Additional Gas**	**TPDC's share of Profit Gas**	**Company's share of Profit Gas**
MMcfd	*Bcf*	*%*	*%*
0 - 20	0-125	75	25
> 20 <= 30	> 125 <= 250	70	30
> 30 <= 40	> 250 <= 375	65	35
> 40 <= 50	> 375 <= 500	60	40
> 50	> 500	45	55

For Additional Gas produced outside of the Proven Section, the Company's Profit Gas share is 55%.

Where TPDC elects to participate in a development program, its profit share percentage increases by the Specified Proportion (for that development program) with a corresponding decrease in the Company's percentage share of Profit Gas.

The Company is liable for income tax in Tanzania. Where income tax is payable, the Company pays the tax and there is a corresponding deduction in the amount of the Profit Gas payable to TPDC.

(j) "Additional Profits Tax" (or "APT") is payable when the Company recovers its costs out of Additional Gas revenues plus an annual operating return under the PSA of 25%, plus the percentage change in the United States Industrial Goods Producer Price Index ("PPI"); and the maximum APT rate is 55% of the Company's Profit Gas when costs have been recovered with an annual return of 35% plus PPI return. The PSA is, therefore, structured to encourage the Company to develop the market and the gas fields in the knowledge that the Profit Gas share can increase with larger daily gas sales and that the costs will be recovered with a 25% plus PPI annual return before APT becomes payable. APT can have a significant negative impact on the project economics if only limited capital expenditure is incurred.

(k) The Company is appointed to develop, produce and process Protected Gas and operate and maintain the Songas gas production facilities and processing plant, including the staffing, procurement, capital improvements, contract maintenance, maintenance of books and records, preparation of reports, maintenance of permits, waste handling, liaison with the Government of Tanzania and taking all necessary safety, health and environmental precautions, all in accordance with good oilfield practices. In return, the Company is paid or reimbursed by Songas so that the Company neither benefits nor suffers a loss as a result of its performance.

(l) In the event of loss arising from Songas' failure to perform, and the loss is not fully compensated by Songas or insurance coverage, then the Company is liable to a performance and operational guarantee of US$2.5 million when (i) the loss is caused by the gross negligence or willful misconduct of the Company, its subsidiaries or employees, and (ii) Songas has insufficient funds to cure the loss and operate the project.

Management's Discussion & Analysis

Results for the year ended December 31, 2017

SUMMARY

During the year ended December 31, 2017 the Company successfully completed the tie in of well SS-11 to the NNGIP infrastructure and the platform work for well SS-12. The flowline connection work for well SS-12 to the NNGIP was in-process at year-end. During Q3 2017 the Company received approval of the AGP2 from the ME which allows PAET to produce and sell increased volumes of Additional Gas. This may be achieved through the Songas infrastructure and by accessing the NNGIP infrastructure. Access to the NNGIP infrastructure is subject to finalizing a new gas sales agreement with TPDC. Once well SS-12 is tied into the NNGIP and the refrigeration unit installation is complete, the Company estimates total field production capabilities will increase to 180 MMcfd. Total cash capital expenditures for the year were US$1.6 million (2016: US$16.9 million).

For the year ended December 31, 2017 there was a decrease of 6% from the prior year in 2P reserve volumes primarily related to gas produced during the year. The decline in sales volume, the change in forecasted sales mix and timing of the sales volume have resulted in the net present value of cash flows from 2P reserves at a 10% discount rate decreasing by 10% compared to the prior year.

The Company's operating revenue decreased by 26% to US$9.7 million in the quarter ended December 31, 2017 (Q4 2016: US$13.2 million) and by 19% to US$44.7 million for the year ended December 31, 2017 (2016: US$55.5 million). The reduction is a combination of lower Cost Gas allocations and the associated increase in Profit Gas attributable to TPDC due to lower sales volumes and the depletion of the cost pool. Revenue for the quarter ended December 31, 2017 decreased by 49% to US$8.5 million (Q4 2016: US$16.8 million) and by 21% for the year ended December 31, 2017 to US$51.9 million (2016: US$65.9 million).

The Company's net cash flows from operating activities for the quarter ended December 31, 2017 increased 54% to US$12.9 million (Q4 2016: US$8.3 million) and increased by 141% to US$48.2 million for the year ended December 31, 2017 (2016: US$20.0 million). The increase is primarily a consequence of the continued improved collections from TANESCO since the third quarter of 2016, which is evidenced by the US$8.4 million deferred revenue recorded on the statement of financial position.

The Company's funds flow from operations for the quarter ended December 31, 2017 decreased 99% to US$0.1 million (Q4 2016: US$6.2 million) and by 53% for the year ended December 31, 2017 to US$14.8 million (2016: US$31.9 million). The decrease is primarily a consequence of the fall in the Company's operating revenue due to lower revenue recognized from sales to TANESCO together with lower sales of Additional Gas volumes, lower Cost Gas and an increase in TPDC Profit Gas entitlement. In addition, as a consequence of the lower capital expenditure during the year, the IFC are entitled to US$3.8 million in Participatory interest in accordance with the terms of the Loan Agreement.

The Company recorded a net loss of US$4.7 million in the quarter ended December 31, 2017 (Q4 2016: US$1.0 million net income) and a net loss of US$2.5 million for the year ended December 31, 2017 (2016: US$2.2 million net income). The loss in the quarter is primarily the result of the lower revenue. The loss for the year is due to a number of factors: (i) the decrease in revenue being partially offset by lower finance expenses; (ii) the decrease in finance expenses being the net effect of lower TANESCO debt write-offs, offsetting the IFC participatory interest; and (iii) the increase in stock based compensation in 2017 being offset by an overall reduction in taxation over the year.

The Company once again exited the year in a stable financial position with US$69.6 million in working capital (Q4 2016: US$72.0 million), cash and cash equivalents of US$122.3 million (Q4 2016: US$80.9 million) and long-term debt of US$58.5 million (Q4 2016: US$58.4 million).

OPERATING VOLUMES

Additional Gas sales volumes for the year ended December 31, 2017 were 15,199 MMcf (2016: 16,291 MMcf) or average daily volumes of 41.6 MMcfd (2016: 44.5 MMcfd). This represents a decrease in average daily volumes of 7% year on year. The decrease in Additional Gas volumes year over year is primarily a result of increased maintenance at the TANESCO power plants resulting in reduced consumption of natural gas by TANESCO compared to 2016.

Additional Gas sales volumes for the quarter, were 3,538 MMcf (Q4 2016: 4,121 MMcf) or average daily volumes of 38.5 MMcfd (Q4 2016: 44.8 MMcfd), a decrease of 14% over the prior year quarter.

The Company's gross sales volumes were split between the Industrial and Power sectors as detailed in the table below:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2017	2016	**2017**	2016
Gross sales volume *(MMcf)*				
Industrial sector	**1,110**	1,226	**4,594**	4,587
Power sector	**2,428**	2,895	**10,605**	11,704
Total volumes	**3,538**	4,121	**15,199**	16,291
Gross daily sales volume *(MMcfd)*				
Industrial sector	**12.1**	13.3	**12.6**	12.5
Power sector	**26.4**	31.5	**29.0**	32.0
Total daily sales volume	**38.5**	44.8	**41.6**	44.5

Industrial sector

Industrial sales volumes for the year were 4,594 MMcf (12.6 MMcfd) compared to 4,587 MMcfd (12.5 MMcfd) for the year ended December 31, 2016. Industrial sales volume decreased by 9% to 1,110 MMcf (12.1 MMcfd) in the quarter from 1,226 MMcf (13.3 MMcfd) in Q4 2016.

The decrease in the quarterly volumes was the result of maintenance work by a cement plant which was marginally offset by the additional consumption of gas by new customers connected during the first quarter of 2017.

Power sector

Power sector sales decreased by 9% to 10,605 MMcf (29.0 MMcfd) for the year ended December 31, 2017 from 11,704 MMcf (32.0 MMcfd) for the year ended December 31, 2016. Power sector sales volumes decreased by 16% to 2,428 MMcf (26.4 MMcfd) in the quarter from 2,895 MMcf (31.5 MMcfd) in Q4 2016.

The decrease in volumes is primarily a result of reduced consumption of gas volumes by TANESCO.

SONGO SONGO DELIVERABILITY

As at December 31, 2017 the Company had a well capacity of approximately 155 MMcfd, with the ability to expand to 180 MMcfd with the tie-in of well SS-12 and the installation of refrigeration. The SS-12 well was successfully completed in the first quarter of 2016 but is currently suspended awaiting tie-in. Production volumes are currently limited to 102 MMcfd, as the Company is producing currently through the Songas infrastructure. The Company will have significant redundant productive capacity once the refrigeration is installed at the Songas gas plant. Well SS-3 is currently suspended and well SS-4 has been shut-in; it is the Company's intention to undertake workovers on both the wells in the future subject to negotiations with Songas, the owner of the wells.

During Q3 2017 the Company, through its subsidiary PAET, received approval of the AGP2 from the ME which allows PAET to produce and sell increased volumes of Additional Gas. This can be achieved through the Songas infrastructure and by accessing the NNGIP infrastructure.

As at December 31, 2017 the SS-11 well is tied into both the Songas and the NNGIP infrastructure however gas sales through the NNGIP are subject to finalizing a new gas sales agreement ("GSA") with TPDC and TPDC resolving some technical issues associated with the design of its facility. The facilities for the connection of the SS-10 well and the SS-12 well to the NNGIP infrastructure are available and can be completed quickly when required and it is currently anticipated that the SS-12 well will be the first well dedicated to the NNGIP infrastructure and SS-10 and SS-11 will be used as and when further volumes to the NNGIP are contracted.

COMMODITY PRICES

The commodity prices achieved in the different sectors during the year is detailed in the table below:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
US$/mcf	**2017**	2016	**2017**	2016
Average sales price				
Industrial sector	**7.78**	7.52	**7.71**	7.70
Power sector	**3.63**	3.57	**3.60**	3.56
Weighted average price	**4.93**	4.75	**4.84**	4.73

Industrial sector

The average gas price achieved during the year was US$7.71/mcf compared to US$7.70/mcf in 2016. The average gas price for the year has remained constant as a consequence of a change in the mix of sales. Lower sales being made to the cement factory in 2017 compared to 2016, increased sales to new industrial companies together with impact of re-setting the floor price for a number of industrial customers at the end of Q3 2016.

The average industrial price in the fourth quarter was US$7.78/mcf (Q4 2016: US$7.52/mcf), as a consequence of lower sales to the cement factory.

Power sector

The average sales price to the Power sector was US$3.60/mcf for the year (2016: US$ 3.56 /mcf) and US$3.63/mcf (Q4 2016: US$3.57/mcf) for the quarter. The 2% increase in price for the year and quarter is a consequence of the annual indexation.

OPERATING REVENUE

Under the terms of the PSA, the Company is responsible for invoicing, collecting and allocating the revenue from Additional Gas sales.

The Company is able to recover all costs incurred on the exploration, development and operations of the project up to a maximum of 75% of the net field revenue ("Cost Gas") prior to the distribution of Profit Gas. Any costs not recovered in any period are carried forward for recovery out of future revenues. Once the Cost Gas has been recovered, TPDC is able to recover any pre-approved marketing costs. Currently there are no pre-approved marketing costs for TPDC.

The average Additional Gas sales volumes for the year were above 40 MMcfd. However, for Q4 2017 and Q2 2017 the Additional Gas volumes were below 40 MMcfd. As a consequence, the Company was entitled to a 35% share of Profit Gas revenue, compared to a 40% share in Q1 2017 and Q3 2017 when the Additional Gas volumes were above 40 MMcfd. The Company was entitled to a 40% share of Profit Gas revenue for all the quarters of 2016 as the Additional Gas volumes for all quarters were above 40 MMcfd. See "Principal Terms of the Tanzanian PSA and Related Agreements."

The Company was allocated a total of 72% of the Songo Songo field net revenue in 2017 (2016: 85%). The decrease in allocation of the net field revenue is a consequence of the depletion of the Cost Pool following the recovery of the capital costs associated with the completion of Phase A of the Development Program. The Offshore Development Program commenced in the third quarter of 2015 and was completed in the first quarter of 2016.

	THREE MONTHS ENDED DECEMBER 31		**YEAR ENDED DECEMBER 31**	
US$'000	**2017**	2016	**2017**	2016
Industrial sector	**8,639**	9,506	**35,440**	35,626
Power sector	**11,870**	8,414	**35,916**	39,751
Gross field revenue	**20,509**	17,920	**71,356**	75,377
Tariff for processing and pipeline infrastructure	**(2,091)**	(2,433)	**(8,978)**	(10,057)
Net field revenue	**18,418**	15,487	**62,378**	65,320
Analysed as to:				
Company Cost Gas	**4,725**	11,615	**34,091**	48,990
Company Profit Gas	**4,984**	1,549	**10,647**	6,532
Company operating revenue	**9,709**	13,164	**44,738**	55,522
TPDC share of revenue	**8,710**	2,323	**17,640**	9,798
Net field revenue	**18,418**	15,487	**62,378**	65,320

The Company's operating revenue decreased by 26% to US$9.7 million in the quarter ended December 31, 2017 (Q4 2016: US$13.2 million) and by 19% to US$44.7 million for the year ended December 31, 2017 (2016: US$55.5 million). The reduction is a combination of lower Cost Gas allocations and the associated increase in Profit Gas attributable to TPDC due to lower sales volumes and the depletion of the cost pool as described above.

Revenue presented on the Consolidated Statements of Comprehensive (Loss) Income may be reconciled to the operating revenue by:

i) Subtracting US$1.2 million income tax for the quarter and adding US$7.1 million for the year. The Company is liable for income tax in Tanzania, but under the terms of the PSA TPDC's Profit Gas entitlement is adjusted for the tax payable. To account for this, revenue is adjusted to include the current income tax charge grossed up at 30%.

Management's Discussion & Analysis

Revenue presented on the Consolidated Statements of Comprehensive Income may be reconciled to the operating revenue as follows:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
US$'000	**2017**	2016	**2017**	2016
Company operating revenue	**9,709**	13,164	**44,738**	55,522
Current income tax adjustment	**(1,191)**	3,670	**7,116**	10,363
Revenue	**8,518**	16,834	**51,854**	65,885

TANESCO impact on revenue

Prior to 2016 the Company had reached an understanding with TANESCO that the Company would continue to supply gas if TANESCO remained reasonably current with payments for gas deliveries. Up to September 30, 2016 the Company recorded revenue from TANESCO based on volumes delivered, however, TANESCO payments were inconsistent and not always in compliance with the agreed understanding. This resulted in the Company recording provisions for doubtful accounts for amounts outstanding from TANESCO for more than 60 days. Commencing on October 1, 2016 the Company began recording revenues for sales to TANESCO based on the expected amount to be collected, which represents a percentage of the amounts invoiced to TANESCO determined by comparison of TANESCO's payment history to the amounts invoiced by the Company over the previous three years. Management believes this approach provides the best estimate of TANESCO's ability to pay and remain reasonably current, and as well, reflects the economic reality of the situation.

For cash received in excess of the revenue recorded from TANESCO in any given period, the additional amounts received will be recorded as deferred revenue. In periods when the deferred revenue balance is greater than the average of amounts invoiced to TANESCO for gas deliveries for the previous four quarters, any amount in excess of the previous four quarter average will be recorded as current period revenue to the extent there is unrecognized revenue resulting from the approach to revenue recognition adopted on October 1, 2016. If such unrecognized revenue is reduced to nil, additional amounts collected in excess of the quarterly average will be applied to pay the oldest TANESCO invoice recorded and previously provided for.

In periods when cash received is less than revenue recorded, the deferred revenue will be reduced accordingly. If the deferred revenue amount is reduced to nil, the difference will be recorded as accounts receivable.

The percentage used to recognize TANESCO revenue will be reviewed on at least a semi-annual basis, more frequently if circumstances require. If there is a significant difference between the amount of revenue recorded and amounts received, the percentage used to record revenue as well as any existing receivable or deferred revenue balance will be revised accordingly. The percentage was increased effective October 1, 2017 to reflect the most recent three year payment history for TANESCO compared to amounts invoiced for deliveries.

As a result of recording revenue based on the expected collectability, there is the following impact on the 2017 results:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
US$'000	**2017**	2016	**2017**	2016
Increase (decrease) in net field revenue and accounts receivable	**3,065**	(1,925)	**(2,247)**	(1,925)
Increase (decrease) in revenue	**1,223**	(1,636)	**83**	(1,636)
Increase (decrease) in net income	**985**	(1,599)	**347**	(1,599)
(Increase) decrease in liabilities	**(2,080)**	326	**2,594**	326

PROCESSING AND TRANSPORTATION TARIFF

The processing and transportation tariff charges for the quarter and for the year were US$2.1 million (Q4 2016: US$2.4 million) and US$9.0 million (2016: US$10.1 million), respectively. The reduction in the tariff for the year is a consequence of the cessation of the additional compensation payments on production volumes in excess of 70 MMcfd commencing in Q2 2016 and lower sales volumes recorded during the periods.

PRODUCTION AND DISTRIBUTION EXPENSES

Well maintenance costs are allocated between Protected Gas and Additional Gas in proportion to their respective sales during the period. The total cost of maintenance for the quarter was US$0.3 million (Q4 2016: US$0.2 million) and for the year, US$0.8 million (2016: US$0.6 million). Amounts allocated for Additional Gas for the quarter and for the year were US$0.1 million (Q4 2016: US$0.1 million) and US$0.4 million (2016: US$0.4 million), respectively.

Other field and operating costs include an apportionment of the annual PSA licence costs, regulatory fees, insurance, some costs associated with the evaluation of the reserves, and the cost of personnel which are not recoverable from Songas.

Distribution costs represent the direct cost of maintaining the ring main distribution pipeline and pressure reduction stations (security, insurance and personnel). Ring main distribution costs were US$0.7 million (Q4 2016: US$0.7 million) for the quarter and US$2.4 million (2016: US$2.7 million) for the year. The production and distribution costs are detailed in the table below:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
US$'000	**2017**	2016	**2017**	2016
Share of well maintenance	**121**	112	**392**	351
Other field and operating costs	**155**	265	**806**	979
	276	377	**1,198**	1,330
Ring main distribution costs	**655**	651	**2,431**	2,703
Production and distribution expenses	**931**	1,028	**3,629**	4,033

Management's Discussion & Analysis

OPERATING NETBACKS

The netback per mcf before general and administrative costs, overhead, tax and APT is detailed in the table below:

US$/mcf	THREE MONTHS ENDED DECEMBER 31 2017	2016	YEAR ENDED DECEMBER 31 2017	2016
Gas price – Industrial	**7.78**	7.52	**7.71**	7.70
Gas price – Power [(1)]	**3.63**	3.56	**3.60**	3.57
Weighted average price for gas	**4.93**	4.75	**4.84**	4.73
Tariff	**(0.59)**	(0.59)	**(0.59)**	(0.62)
TPDC share of revenue	**(1.81)**	(0.56)	**(1.01)**	(0.60)
Net selling price	**2.53**	3.60	**3.24**	3.51
Well maintenance and other operating costs	**(0.08)**	(0.09)	**(0.08)**	(0.08)
Ring main distribution costs	**(0.19)**	(0.16)	**(0.16)**	(0.17)
Operating netbacks	**2.26**	3.35	**3.00**	3.26

(1) *The weighted average sales price is stated before the decrease in TANESCO revenue due to the modified approach used for revenue recognition purposes and represents the weighted average price of the volumes invoiced and delivered.*

The operating netback in the quarter decreased by 32% to US$2.26/mcf from US$3.35/mcf in Q4 2016. The decrease in the quarter is predominately due to the increase in TPDC share of revenue to US$1.81/Mcf from US$0.56/Mcf. The increase is the combination of the depletion of the costs pool and lower Additional Gas volumes. The increase in TPDC share was offset to a small extent by the increase in the weighted average price for gas to US$4.93/Mcf from US$4.75/Mcf as a consequence of the change in the sales mix.

The operating netback for the year decreased 8% to US$3.00/mcf from US$3.26/mcf in 2016. The decrease is due to the increase in TPDC share of net field revenue, being offset to a small extent by the increase on the weighted average price for gas to US$4.84/Mcf from US$4.73/Mcf. The increase in the weighted average price for gas is the consequence of the relative increase of industrial sales to total sales, the overall level of industrial sales remaining constant over the two years.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses are detailed in the table below:

US$'000	THREE MONTHS ENDED DECEMBER 31 2017	2016	YEAR ENDED DECEMBER 31 2017	2016
Employee and related costs	**2,712**	2,514	**7,147**	8,050
Stock based compensation	**2,075**	556	**6,619**	2,591
Office costs	**1,054**	1,317	**3,759**	3,618
Marketing and business development costs	**762**	42	**1,307**	322
Reporting, regulatory and corporate	**716**	459	**1,976**	1,756
General and administrative expenses	**7,319**	4,888	**20,808**	16,337

General and administrative expenses include the costs of running the natural gas distribution business in Tanzania which is recoverable as Cost Gas and is relatively fixed in nature. Excluding stock based compensation and other expenses, general and administrative expenses averaged US$1.7 million (Q4 2016: US$1.5 million) per month during the quarter and US$1.2 million (2016: US$1.2 million) per month over the year.

STOCK BASED COMPENSATION

The breakdown of the costs incurred in relation to stock based compensation is detailed in the table below:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
US$'000	**2017**	2016	**2017**	2016
Stock appreciation rights ("SARs")	**904**	439	**2,271**	1,467
Restricted stock units ("RSUs")	**1,171**	117	**4,348**	1,124
Stock-based compensation	**2,075**	556	**6,619**	2,591

As at December 31, 2017 a total of 2,485,000 SARs were outstanding compared to 2,430,000 as at December 31, 2016. A total of 350,000 SARs with exercise prices ranging from CDN$2.30 to CDN$3.25 were exercised during the year resulting in a total cash payout of US$0.4 million. A total of 365,000 SARs where granted during the year. All the newly issued SARs have a five-year term, vest equally over five years with the first fifth vesting on the anniversary of the grant date and have exercise prices ranging from CDN$3.84 to CDN$3.87. A total of 50,000 SARs were forfeited during the year with a further 90,000 SARs issued that fully vest in 2019. As at December 31, 2017 a total of 1,147,621 RSUs were outstanding compared to 239,361 at December 31, 2016. During the year a total of 1,402,322 RSUs were issued, of which 402,322 RSUs vested in full on the date of issue. The remaining 1,000,000 RSUs issued vested quarterly from July 1, 2017 and fully vested on March 31, 2018. All the RSUs issued have an exercise price of CDN$0.001 with a term of five years. A total of 494,062 RSUs were exercised during the year resulting in a total cash payout of US$1.5 million.

As SARs and RSUs are settled in cash, they are re-valued at each reporting date using the Black-Scholes option pricing model with the resulting liability being recognized in trade and other payables. In the valuation of stock appreciation rights and restricted stock units at the reporting date, the following assumptions have been made: a risk free rate of interest of 1.0%; stock volatility of 32.4% to 53.3%; 0% dividend yield; 5% forfeiture; and a closing price of CDN$5.00 per Class B share.

As at December 31, 2017 a total accrued liability of US$7.9 million (2016: US$3.2 million) has been recognized in relation to SARS and RSUs. The Company recognized an expense of US$2.1 million (Q4 2016: US$0.6 million) for the quarter and for the year ended December 31, 2017 an expense of US$6.6 million (2016: US$2.6 million). The increased expense in 2017 is due to the combination of a 30% increase in the share price to CDN$5.00 (2016: CDN$3.86) together with new issues of both SARS and RSUs during the first half of the year.

NET FINANCE EXPENSE

Net finance expense is detailed in the table below:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
US$'000	**2017**	2016	**2017**	2016
Finance income	**155**	193	**366**	383
Interest expense	**(1,594)**	(1,567)	**(6,250)**	(5,668)
Participatory interest	**(1,031)**	–	**(3,809)**	–
Net foreign exchange loss	**64**	(18)	**184**	(24)
Provision for doubtful accounts	**90**	(414)	**90**	(12,853)
Indirect tax	**(253)**	(1,388)	**(3,046)**	(1,392)
Finance expense	**(2,724)**	(3,387)	**(12,831)**	(19,937)

During 2017 the Company invoiced TANESCO US$6.5 million (2016: US$4.2 million) of interest for late payments and US$13.4 million (2016: US$7.8 million) for differences between gas contracted for delivery versus gas taken by TANESCO in accordance with the provisions of the PGSA. Neither the interest nor the other contractual invoices have been included in the financial statements as they do not meet the revenue recognition criteria with respect to assurance of collectability. However, the VAT associated with the interest and the other contractual invoices has been provided for in the indirect tax line shown in the analysis above.

The interest expense and participatory interest expense relate to the long-term loan with the IFC. The amount of interest paid during the year was US$6.3 million (2016: US$5.7 million), the interest is payable quarterly in arrears. The participatory interest expense of US$3.8 million (2016:US$ nil) is paid annually in arrears, it equates to 7% of PAET's net cash flows from operating activities net of net cash flows used in investing activities for the year (see "Long-Term Loan").

The provision for doubtful accounts for the year ended December 31, 2017 of US$0.1 million represents a receipt from an industrial debtor which had been previously provided against. The provision for doubtful accounts for the year ended December 31, 2016 includes US$12.4 million for overdue TANESCO receivables and US$0.4 million relates to Industrial customers. Prior to October 1, 2016 any TANESCO receivable which was older than 60 days was provided for and a provision for doubtful accounts was recognized in the financial statements.

TANESCO

At December 31, 2017 the current receivable from TANESCO was US$ nil (December 31, 2016: US$5.7 million). During the year the amounts received from TANESCO were in excess of the revenue recognized for gas sales to TANESCO resulting in a deferred revenue of US$8.4 million (December 31, 2016: US$ nil) after the recognition of US$3.8 million deferred revenue in the current period.

The long-term trade receivable at December 31, 2017 and 2016 was US$74.4 million (provision of US$74.4 million). Subsequent to December 31, 2017 the Company has invoiced TANESCO US$6.2 million for 2018 gas deliveries and TANESCO has paid the Company US$10.0 million.

The following table reconciles the total amount receivable from TANESCO including amounts not meeting revenue recognition criteria reconciled to the amounts recorded in the consolidated financial statements:

US$'000	**AS AT DECEMBER 31 2017**	2016
Total TANESCO receivable	**108,833**	100,776
Unrecognized amounts for not meeting revenue recognition criteria [1]	**(38,710)**	(18,741)
Invoiced amounts reduced based on TANESCO's payment history for the previous three years	**(4,172)**	(1,925)
Provision for doubtful accounts	**(74,361)**	(74,361)
TANESCO (deferred revenue) current receivable balance per consolidated financial statements	**(8,410)**	5,749

[1] The amount includes invoices for interest on late payments and invoices relating to differences between gas contracted for delivery versus gas taken by TANESCO.

TAXATION

Income Tax

Under the terms of the PSA with TPDC and the Government of Tanzania, the Company is liable for income tax in Tanzania at the corporate tax rate of 30%. However, the PSA provides a mechanism by which income tax payable is recovered from TPDC by reducing TPDC's share of Profit Gas and increasing the allocation to the Company. This is reflected in the accounts by increasing the Company's share of revenue by an amount equivalent to income taxes payable.

As at December 31, 2017 there were temporary differences between the carrying value of the assets and liabilities for financial reporting purposes and the amounts used for taxation purposes under the Income Tax Act 2004. Applying the 30% Tanzanian tax rate, the Company has recognized a deferred tax liability of US$11.8 million (2016: US$13.0 million). During the year there was a deferred tax recovery of charge of US$1.1 million compared to a deferred tax charge of US$3.7 million in 2016. The deferred tax has no impact on cash flow until it becomes a current income tax, at which point the tax is paid and recovered from TPDC's share of Profit Gas.

Additional Profits Tax

Under the terms of the PSA, in the event that all costs have been recovered with an annual return of 25% plus the percentage change in the United States Industrial Goods Producer Price Index ("PPI"), an Additional Profits Tax is payable.

The timing and the effective rate of APT depends on the realized value of Profit Gas which in turn depends of the level of expenditure. The Company provides for APT by forecasting annually the total APT payable in the future as a proportion of the forecast Profit Gas over the term of the PSA. The forecast takes into account the timing of future development capital spending.

The Company provides for APT by forecasting the total APT payable as a proportion of the forecast Profit Gas over the term of the PSA. The effective APT rate for the quarter of 19.25% (Q4 2016: 19.44%) has been applied to Profit Gas of US$5.0 million (Q4 2016: US$1.5 million), and an average effective rate of 19.38% (2016: 18.80%) has been applied to Profit Gas of US$10.6 million (2016: US$6.5 million) for the year ended December 31, 2017. Accordingly, US$1.0 million (Q4 2016: US$0.3 million) and US$2.1 million (2016: US$1.2 million) have been recorded for the quarter, and for the year ended December 31, 2017, respectively.

	THREE MONTHS ENDED DECEMBER 31		**YEAR ENDED DECEMBER 31**	
US$'000	**2017**	2016	**2017**	2016
Additional Profits Tax	**962**	301	**2,063**	1,226

DEPLETION AND DEPRECIATION

Natural gas properties are depleted using the unit of production method based on the production for the period as a percentage of the total future production from the Songo Songo proved reserves. As at December 31, 2017 the estimated proved reserves remaining to be produced over the term of the PSA licence were 307 Bcf (2016: 347 Bcf). A depletion expense of US$2.0 million for the quarter (Q4 2016: US$2.4 million) and US$8.7 million for the year (2016: US$9.2 million) has been recorded in the accounts at an average depletion rate to US$0.58/mcf (2016: US$0.56/mcf).

Non-natural gas properties are depreciated as follows:

Leasehold improvements:	Over remaining life of the lease
Computer equipment:	3 years
Vehicles:	3 years
Fixtures and fittings:	3 years

CARRYING AMOUNT OF ASSETS

Capitalized costs are periodically assessed to determine whether it is likely that such costs will be recovered in the future. To the extent that these capitalized costs are less than their recoverable amount, they are impaired and recorded in earnings

CAPITAL EXPENDITURES

During 2017 the Company incurred US$1.5 million (2016: US$16.9 million) in capital expenditures relating primarily to the completion of the platform for the well SS-12 and the connection of the SS-11 well to the NNGIP infrastructure. The 2016 capital expenditures related to the completion of the well SS-12.

	THREE MONTHS ENDED DECEMBER 31		**YEAR ENDED DECEMBER 31**	
US$'000	**2017**	2016	**2017**	2016
Geological and geophysical and well drilling	**–**	32	**30**	16,255
Pipelines and infrastructure	**442**	99	**1,262**	565
Other equipment	**30**	–	**253**	104
	472	131	**1,545**	16,924
Other [(1)]	**–**	–	**7,352**	–
	472	131	**8,897**	16,924

(1) *In Q1 2017, based on agreement with TPDC, the Songas share of workover costs incurred in 2015 were transferred to the cost pool to recover the costs via the PSA cost recovery mechanism. This resulted in US$7.4 million of the Songas receivable being reclassified to plant, property and equipment equal to the proportion not previously provided against. This represents the value which will be recovered via the PSA revenue sharing mechanism.*

FUNDS FLOW FROM OPERATIONS

Funds flow from operations was US$0.1 million for Q4 2017 (Q4 2016: US$6.2 million) and US$14.8 million for the year (2016: US$31.9 million) and is detailed in the table below:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
US$'000	**2017**	2016	**2017**	2016
Operating activities				
Net (loss) income	**(4,684)**	1,048	**(2,500)**	2,164
Non-cash adjustments	**4,747**	5,163	**17,340**	29,691
Funds flow from operations [1]	**63**	6,211	**14,840**	31,855
Interest paid	**1,594**	1,567	**6,250**	5,668
Participatory interest	**1,031**	–	**3,809**	–
Changes in non-cash working capital [2]	**10,194**	567	**23,255**	(17,555)
Net cash flows from operating activities	**12,882**	8,345	**48,154**	19,968
Net cash (used in) from investing activities	**(500)**	7	**(1,683)**	(27,609)
Net cash (used in) from financing activities	**(602)**	(1,566)	**(5,258)**	34,132
Increase in cash	**11,780**	6,786	**41,213**	26,491
Effect of change in foreign exchange on cash	**54**	30	**214**	607
Net increase in cash	**11,834**	6,816	**41,427**	27,098

(1) *See non-GAAP measures*

(2) *See Consolidated Statements of Cash Flows*

The Company's funds flow from operations for the quarter ended December 31, 2017 decreased 99% to US$0.1 million (Q4 2016: US$6.2 million) and by 53% for the year ended December 31, 2017 to US$14.8 million (2016: US$31.9 million). The decrease is primarily a consequence of the fall in the Company's operating revenue due to the lower revenue recognized from sales to TANESCO together with lower sales of Additional Gas volumes, lower Cost Gas and an increase in TPDC Profit Gas entitlement. In addition, as a consequence of the lower capital expenditure during the year the IFC is entitled to US$3.8 million in participatory interest in accordance with the terms of the Loan Agreement.

The Company's net cash flows from operating activities for the quarter ended December 31, 2017 increased by 54% to US$12.9 million (Q4 2016: US$8.3 million) and increased by 141% to US$48.2 million for the year ended December 31, 2017 (2016: US$20.0 million). The increase is primarily a consequence of the continued improved collections from TANESCO since the third quarter of 2016, which is evidenced by the US$8.4 million deferred revenue recorded on the statement of financial position together with the recognition of US$3.8 million of deferred revenue in the current period. The deferred revenue recognized in the current period income statement represents the excess amount over and above the quarterly average amount invoiced to TANESCO for deliveries.

WORKING CAPITAL

Working capital as at December 31, 2017 was US$69.6 million (December 31, 2016: US$72.0 million) and is detailed in the table below:

				AS AT DECEMBER 31
US$'000		**2017**		2016
Cash		**122,322**		80,895
Trade and other receivables		**12,273**		27,638
TANESCO	–		5,749	
Songas	2,378		2,218	
Industrial customers	6,915		7,463	
Songas gas plant operations	5,827		6,601	
Songas well workover program [(1)]	–		14,458	
Other receivables	2,521		1,516	
Provision for doubtful accounts	(5,368)		(10,367)	
Prepayments		**866**		651
		135,461		109,184
Trade and other payables		**65,168**		34,305
TPDC share of Profit Gas [(2)]	33,422		22,917	
Songas	1,670		1,893	
Other trade payables	1,961		3,245	
Accrued liabilities	19,705		6,250	
Deferred income	8,410		–	
Tax payable		**718**		2,890
		66,886		37,195
Working capital [(3)]		**69,575**		71,989

[(1)] *In Q1 2017 the receivable related to the Songas workovers was adjusted to reflect that the costs had been transferred to the cost pool in order to recover the costs via the PSA cost recovery mechanism based on agreement with TPDC. This resulted in the receivable being adjusted by: i) US$7.4 million being reclassified to plant, property and equipment equal to the proportion not previously provided against. This represents the value which will be recovered via the PSA revenue sharing mechanism; ii) the write-off of the US$4.9 million portion of the Songas receivable that had been previously provided for; and iii) US$2.2 million relating to VAT on the workovers that had already been paid being reclassified as a long-term receivable.*

[(2)] *The balance of US$33.4 million payable to TPDC is the accrued liability for their share of profit gas delivered to TANESCO which has not been paid for, net of US$2.4 million previously recorded as tax recoverable. The majority of the settlement of this liability is dependent on receipt of payment from TANESCO for arrears.*

[(3)] *Working capital as at December 31, 2017 includes TANESCO deferred revenue of US$8.4 million (December 31, 2016: US$ nil). The deferred revenue is a consequence of the cumulative cash collected from TANESCO during the year ending December 30, 2017 being in excess of the invoiced amounts recognized as revenue during the same period. Correspondingly, as at December 31, 2017 there is no current receivable for TANESCO (December 31, 2016: US$5.7 million). The total of long and short-term TANESCO receivables as at December 31, 2017, including unrecorded interest and revenue as a result of issued invoices not meeting revenue recognition criteria, was US$108.8 million. The Company is actively pursuing the collection of all the receivables that have been charged to TANESCO.*

Working capital as at December 31, 2017 decreased by 3% over December 31, 2016 and decreased by 2% during the quarter. The successful collection of TANESCO receivables has increased current assets by US$20.9 million despite the net decrease in the Songas receivable of US$9.5 million for workover costs. This has been offset by an increase in current liabilities of US$29.7 million as a result of the increase in the TPDC Share of Profit Gas of US$10.5 million, the US$3.8 million participatory interest payable to the IFC, the US$8.4 million deferred revenue and the US$4.0 million increase in the stock based compensation liability.

Other significant points are:

- There are no restrictions on the movement of cash from Mauritius or Tanzania, and over 90% of the Company's cash is currently held outside of Tanzania.
- Of the US$6.9 million relating to industrial customers US$6.0 million had been received as at the date of this report.

LONG TERM LOAN

The Company's subsidiary, PAET, entered into a loan agreement (the "Loan") in 2015 with the International Finance Corporation ("IFC"), a member of the World Bank Group, for US$60 million. The Loan was fully drawn down in 2016.

The term of the Loan is 10-years, with no required repayment of principal for the first seven years, followed by a three-year amortization period. The Loan is to be paid out through six semi-annual payments of US$5 million starting April 15, 2022 and one final payment of US$30 million due on April 15, 2025. The Company may voluntarily prepay all or part of the Loan but must simultaneously pay any accrued base interest costs related to the principal amount being prepaid. If any portion of the Loan is prepaid prior to the fourth anniversary of the first drawdown, the Company would be required to pay the accrued base interest as if the prepaid portion of the Loan had remained outstanding for the full four years. The Loan is an unsecured subordinated obligation of PAET and is guaranteed by the Company to a maximum of US$30 million. The guarantee may only be called upon by IFC at maturity in 2025. Subject to receipt of the IFC approval and required regulatory approvals, the Company at its discretion may issue shares in fulfillment of all or part of the guarantee obligation in 2025.

Base interest on the Loan is payable quarterly at 10% per annum on a 'pay-if-you-can-basis' using a formula to calculate the net cash available for such payments as at any given interest payment date. The Company must provide notice to the IFC of the amount of any interest which is not to be paid on any interest payment date. Any unpaid interest is added to the principal outstanding and may be paid out before or at the time of principal repayment. To date all interest incurred has been paid. In addition, an annual variable participatory interest equating to 7% of the net cash flow from operating activities less net cash flows used in investing activities of PAET in respect of any given year. Such participatory interest will continue until October 15, 2026 regardless whether the Loan is repaid prior to its contractual maturity date. For the year ended December 31, 2017 the participatory interest was US$3.8 million (2016: US$ nil) and is included in trade and other payables. Dividends and distributions from PAET to the Company are restricted at any time that any amounts of unpaid interest, principal or participating interest are outstanding.

OUTSTANDING SHARES

There were 35,256,432 shares outstanding as at December 31, 2017 as detailed in the table below:

	AS AT DECEMBER 31	
Number of shares ('000)	**2017**	2016
Shares outstanding		
Class A shares	**1,751**	1,751
Class B shares	**33,506**	33,106
Class A and Class B shares outstanding	**35,257**	34,857
Weighted average		
Class A and Class B shares	**34,858**	34,857
Convertible securities		
Options	**–**	–
Weighted average diluted Class A and Class B shares	**34,858**	34,857

As at the date of this report there were a total of 1,750,517 Class A common voting shares ("Class A shares") and 33,505,915 Class B subordinated voting shares ("Class B shares") outstanding. A total of 400,000 Class B subordinated voting shares were issued on December 31, 2017 after the exercise of options.

RELATED PARTY TRANSACTIONS

One of the non-executive Directors is counsel to a law firm that provides legal advice to the Company and its subsidiaries. During the quarter costs of US$0.6 million (Q4 2016: US$0.1 million) and US$0.9 million for the year ended December 31, 2017 (2016: US$0.2 million) were incurred by this firm for services provided. As at December 31, 2017 the Company has a total of US$0.5 million (2016: US$0.1 million) recorded in trade and other payables in relation to the related party.

CONTRACTUAL OBLIGATIONS AND COMMITTED CAPITAL INVESTMENT

Protected Gas

Under the terms of the original Gas Agreement for the Songo Songo project ("Gas Agreement"), in the event that there is a shortfall/insufficiency in Protected Gas as a consequence of the sale of Additional Gas, the Company is liable to pay the difference between the price of Protected Gas (US$0.55/MMbtu escalated) and the price of an alternative feedstock multiplied by the volumes of Protected Gas up to a maximum of the volume of Additional Gas sold (176.4 Bcf as at December 31, 2017). The Company did not have a shortfall during the reporting period and does not anticipate a shortfall arising during the term of the Protected Gas delivery obligation to July 2024.

Additional Gas Plan 2 ("AGP2")

During Q3 2017 the Company received approval of the AGP2 from the ME which allows PAET to produce and sell increased volumes of Additional Gas. This may be achieved through the Songas infrastructure and by accessing the NNGIP infrastructure. Wells SS-11, and SS-12 have been connected to the NNGIP infrastructure subject to TPDC finalizing certain technical matters pertaining to the operation of the wells at their facility and the establishment of a new gas sales agreement by PAET with TPDC. Well SS-10 has also been identified for possible connection to the NNGIP facility, subject to the same conditions.

Re-Rating Agreement

In 2011 the Company signed a re-rating agreement with TANESCO, TPDC and Songas (the "Re-Rating Agreement") which evidenced an increase to the gas processing capacity of the Songas facilities to a maximum of 110 MMcfd (the pipeline and pressure requirements at the Ubungo power plant restrict the infrastructure capacity to a maximum of 102 MMcfd). Under the terms of the Re-Rating Agreement, the Company paid additional compensation of US$0.30/mcf for sales between 70 MMcfd and 90 MMcfd and US$0.40/mcf for volumes above 90 MMcfd by issuing credit notes to TANESCO. This was in addition to the tariff of US$0.59/mcf payable to Songas as set by the energy regulator, EWURA.

Although Songas notified the Company in 2014 that the Re-Rating Agreement was terminated, the parties have continued to produce, transport and sell gas volumes in line with the re-rated plant capacity. In May 2016 the Company notified TANESCO and Songas that the additional compensation for sales over 70 MMcfd would no longer be paid effective June 2016. The additional compensation was always intended to be temporary in nature until the expansion of the Songas infrastructure, at which time Songas would apply to EWURA to obtain approval of a new tariff for the processing of volumes over 70 MMcfd. The PGSA provides for passing on to TANESCO any tariff charged to the Company in the event that a new tariff is approved.

The parties are seeking to resolve the status of the re-rating agreement. The processing capacity at the Songas facilities remains unaltered and is fully available for utilization by the Company. This capacity is in addition to the capacity available within the NNGIP infrastructure which PAET intends to utilize now that AGP2 is approved.

Portfolio Gas Supply Agreement

In June 2011 the PGSA was signed (term to June 30, 2023) between TANESCO (as the buyer) and the Company and TPDC (collectively as the seller). Under an amendment to the PGSA (effective January 29, 2018), the seller is obligated, subject to infrastructure capacity, to sell a maximum of approximately 26 MMcfd (previously 36 MMcfd) for use in any of TANESCO's current power plants, except those operated by Songas at Ubungo. Under the agreement, the basic wellhead price of approximately US$2.98/mcf increased to US$3.04/mcf on July 1, 2017. Previously under the PGSA any sales in excess of 36 MMcfd were subject to a 150% increase in the basic wellhead gas price. During the year ended December 31, 2017 the average sales to TANESCO were 20.7 MMcfd.

Operating leases

The Company has two office rental agreements, one in Dar es Salaam, Tanzania and one in Winchester, United Kingdom. The agreement in Dar es Salaam expires on October 31, 2019 at an annual rent of US$0.3 million. The agreement in Winchester expires on September 25, 2022 at an annual rental of US$0.1 million per annum. The costs of these leases are recognized in the general and administrative expenses.

Capital Commitments

Italy

The Company has an agreement to farm in on Central Adriatic B.R268.RG Permit offshore Italy. The farm-in commits the Company to fund 30% of an appraisal well up to a maximum of US$11.5 million to earn a 15% working interest in the permit. Thereafter, the Company will fund all future costs relating to the well and the permit in proportion to its participating interest. The Company has also agreed to pay fifteen per cent (15%) of the back costs in relation to the well up to a maximum of US$0.5 million. Changes in Italian environmental legislation in late 2015 have resulted in the development of this permit being postponed until the development plan is approved. As at the date of this report, the Company has no further capital commitments in Italy.

Tanzania

There are no contractual commitments for exploration or development drilling or other field development either in the PSA or otherwise agreed which would give rise to significant capital expenditure at Songo Songo. Any significant additional capital expenditure in Tanzania is discretionary.

The completion of the offshore component of Phase A of the Development Program in February 2016 improved field deliverability and provided sufficient natural gas production to fill the Songas plant and pipeline to capacity for the greater portion of the remaining life of the production licence. With the signing of AGP2, the Company is planning to continue with the completion of Phase A of the Development Program that includes a refrigeration unit and well workovers with an estimated cost of US$22 million. A portion of the costs are for workovers on wells SS-3 and SS-4 and assuming Songas, the owner of the wells, will fund the costs for these workovers, the net estimated cost to the Company will be US$13.3 million.

During 2017 the Company connected well SS-11 to the NNGIP infrastructure and is currently finalizing commercial terms with TPDC for the sale of incremental gas volumes through the NNGIP.

At the date of this report, the Company has no significant outstanding contractual commitment, and has no outstanding orders for long lead items related to any capital programs.

CONTINGENCIES

Petroleum Act, 2015

The Petroleum Act, 2015 (the "Petroleum Act") repeals earlier legislation, provides a regulatory framework over upstream, mid-stream and downstream gas activity, and consolidates and puts in place a comprehensive legal framework for regulating the oil and gas industry in the country. The Petroleum Act also provides for the creation of an upstream regulator, the Petroleum Upstream Regulatory Authority ("PURA"). The mid and downstream oil and gas activities are proposed to be regulated by the current authority, the Energy and Water Utilities Regulatory Authority (EWURA). The Petroleum Act also confers upon TPDC, the status of the National Oil Company, mandated with the task of managing the country's commercial interest in petroleum operations as well as mid and downstream natural gas Petroleum Activities. The Petroleum Act vests TPDC with exclusive rights in the entire petroleum upstream and the natural gas mid and downstream value chains. However, the exclusive rights of TPDC do not extend to mid and downstream petroleum supply operations. The Petroleum Act does provide grandfathering provisions, upholding the rights of the Company under their PSA as it was signed prior to passing of the Petroleum Act. However, it is still unclear how the provisions of the Petroleum Act will be interpreted and implemented regarding upstream and downstream activities and the Company is uncertain regarding the potential impact on its business in Tanzania.

On October 7, 2016 the Government of Tanzania issued the Petroleum (Natural Gas Pricing) Regulation made under Sections 165 and 258 (l) of the Petroleum Act. Under the Petroleum Act, Article 260 (3) preserves the Company's pre-existing right with TPDC to market and sell Additional Gas together or independently on terms and conditions (including prices) negotiated with third party natural gas customers. The impact of the Natural Gas Pricing Regulation, if any, cannot be determined at this time.

TPDC Back-in

TPDC has the rights under the PSA to 'back in' to the Songo Songo field development and to convert this into a carried working interest in the PSA. The current terms of the PSA require TPDC to provide formal notice in a defined period and contribute a proportion of the costs of any development, sharing in the risks in return for an additional share of the gas. To date, TPDC has not contributed any costs nor provided any formal notice of intent to do so.

Cost recovery

TPDC conducted an audit of the historic Cost Pool and in 2011 disputed approximately US$34 million of costs that had been recovered from the Cost Pool from 2002 through to 2009. In 2014 a substantial portion of the disputed costs were agreed to be cost recoverable by TPDC. Under the dispute mechanism outlined in the PSA, TPDC are to appoint an independent specialist to assist the parties in reaching agreement on costs that are still subject to dispute. In 2014, prior to appointing an independent specialist, TPDC suspended the process. There have been no further developments regarding the dispute since this suspension, and at the time of writing this report no such specialist has been appointed. If the matter is not resolved to the Company's satisfaction, the Company intends to proceed to arbitration via the International Centre for Settlement of Investment Disputes ("ICSID") pursuant to the terms of the PSA.

Taxation

		Tax dispute	Disputed amount US$' million		
Area	**Period**	**Reason for dispute**	**Principal**	**Interest**	**Total**
Pay-As-You-Earn ("PAYE") tax	2008-10	PAYE tax on grossed-up amounts in staff salaries which are contractually stated as net.	0.3	–	0.3 *(1)*
Withholding tax ("WHT")	2005-10	WHT on services performed outside of Tanzania by non-resident persons.	1.1	0.7	1.8 *(2)*
Income Tax	2008-15	Deductibility of capital expenditures and expenses (2009 and 2012), additional income tax (2008, 2010, 2011 and 2012), tax on repatriated income (2012), foreign exchange rate application (2013 and 2015) and underestimation of tax due (2014).	29.6	10.0	39.6 *(3)*
VAT	2008-10	Output VAT on imported services and SSI Operatorship services.	2.7	2.8	5.5 *(4)*
			33.7	13.5	47.2

Management, with the advice from its legal counsels, has reviewed the Company's position on the objections and appeals related to the disputed amounts and has concluded that no provision is required with regard to these matters and that the maximum potential exposure is US$47.2 million (2016: US$34.6 million).

(1) In 2015 PAET appealed the Tax Revenue Appeals Board ("TRAB") ruling that PAET is liable to pay PAYE on grossed-up amounts on staff salaries. TRAB waived interest assessed thereon. The Tax Revenue Appeal Tribunal ("TRAT") upheld Tax Revenue Appeal Board ("TRAB") decision which ruled in favour TRA on principal tax demanded but waived interest assessed thereon. In 2017 PAET appealed the TRAT ruling to the Court of Appeal of Tanzania ("CAT"). PAET is awaiting CAT hearing date to be set.

(2) (a) 2005-2009 (US$1.7 million): In 2016 TRA filed an application for review of the CAT decision in favour of PAET and later filed another application for leave to amend its earlier application. At the CAT hearing in Q1 2017 TRA withdrew their second application for review. In Q2 2017 the CAT accepted PAET's preliminary objection against the TRA application. On July 28, 2017 TRA filed another Application for extension of time, under the certificate of urgency, for their application for CAT leave to review its judgement. Subsequent to year end CAT ruled in favour of PAET's preliminary objection. TRA still has the right to amend and re-file its application;

(b) 2010 (US$0.1 million): TRAB is awaiting a ruling from the review by the Court of Appeal on the 2005-2009 case which would influence TRAB's decision on this matter accordingly;

(3) (a) *2009 (US$2.6 million): In 2015 TRAB ruled against PAET with respect to timing of deductibility of capital expenditures and other expenses (US$1.8 million). In Q2 2017 PAET lost an appeal at TRAT and subsequently filed an appeal to CAT and is awaiting a hearing date to be set. In July 2017 TRA sent PAET an amended assessment claiming additional taxes, interest and penalties (US$0.8 million). PAET has objected to the assessment for being time-barred and arbitrary and is awaiting TRA response;*

(b) *2008 (US$0.6 million): In Q2 2017 TRA issued an adjusted assessment which accepted PAET's position that there was no tax payable for the year. The assessment, however, did not recognize a tax loss carried forward of US$1.8 million (with tax impact of US$0.6 million). PAET has objected to the assessment for being time-barred, incorrect and arbitrary;*

(c) *2011 (US$2.0 million): In Q2 2017 PAET filed an appeal at TRAB against a TRA assessment with respect to timing of deductibility of capital expenditures and other expenses (US$1.8 million). PAET is awaiting a TRAB hearing date. PAET is also awaiting a TRA response on an objection of another assessment with respect to alleged late filing penalty and under-estimation of interest (US$0.2 million) raised for the year;*

(d) *2010 (US$2.4 million): PAET filed an appeal with TRAB against a TRA assessment with respect to timing of deductibility of capital expenditures and other expenses as well as underestimation of interest and penalty amounts. PAET is awaiting a hearing date to be scheduled;*

(e) *2013 (US$6.6 million): In 2016 PAET filed objections to a TRA assessment with respect to foreign exchange rate application and is awaiting a response. PAET has received TRA assessments for corporation tax (US$0.9 million) which disallowed certain operating costs included in the tax returns and tax on repatriated income (US$5.7 million). PAET has objected to the assessments due to being time-barred and without merit. PAET has also appealed to TRAB the TRA decision not to exercise its administrative powers judiciously to grant the waiver on one-third deposit required to be paid to admit the objection and is awaiting the hearing date to be scheduled;*

(f) *2012 (US$15.8 million): In 2016 TRA issued two assessments with respect to understated revenue, timing of deductibility of capital expenditures, expenses and tax on repatriated income. PAET filed an appeal with TRAB against the TRA decision to deny PAET a waiver for payment of a deposit which is required for its objection to be admitted but was granted a partial waiver only. PAET appealed the decision demanding full waiver of the deposit and also filed an application for the stay of execution with TRAT in response to the TRA demand notice for the payment of the deposit ruled by TRAB. TRAT upheld the TRAB decision for partial waiver. Managementhas decided to appeal the TRAT decision and has fourteen days from the date of TRAT decision to file a Notice of Appeal;*

(g) *2014 (US$9.2 million): In 2016 TRA issued an assessment of US$3.3 million with respect to underestimation of tax due based on the provisional quarterly payments made by PAET, delayed filings of returns and late payments. PAET filed objections to the assessments and is awaiting a response. PAET has also appealed to TRAB the TRA decision not to exercise its administrative powers judiciously to grant the waiver on one-third deposit required to be paid to admit the objection and is awaiting the hearing date to be scheduled. TRA has issued two additional assessments for the year for corporation tax of US$3.1 million and tax on repatriated income US$2.8 million. PAET has objected the assessments and is awaiting TRA response;*

(h) *2015 (US$0.4 million): In 2016 TRA issued a self-assessment. PAET filed an objection to the assessment with respect to foreign exchange rate application and is awaiting a response;*

(4) (a) *2008-2010 (US$5.4 million): In 2016 TRA responded to PAET's objection filed in 2014 and issued an assessment in respect of output VAT on imported services and SSI Operatorship services. PAET filed an appeal with TRAB against the TRA assessment and is awaiting a hearing date to be scheduled;*

(b) *2012-2014 (US$ 0.1 million): TRA has issued an assessment for VAT on other income that PAET had paid. PAET has objected the assessment and is awaiting TRA response.*

FUTURE ACCOUNTING CHANGES

The following pronouncements from the IASB will become effective or were amended for financial reporting periods beginning on or after January 1, 2018 and have not yet been adopted by the Company. These new or revised standards permit early adoption with transitional arrangements depending upon the date of initial application.

IFRS 9 – Financial Instruments replaces the existing guidance in IAS 39 Financial Instruments: Recognition and Measurement. The new standard includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for calculating impairment on financial assets, and the new general hedge accounting requirements. It also carries forward the guidance on recognition and de-recognition of financial instruments from IAS 39. IFRS 9 is effective for annual reporting periods beginning on or after January 1, 2018 with early adoption permitted. The Company currently does not apply hedge accounting to its financial instruments and does not currently intend to apply hedge accounting to any of its financial instruments upon adoption of IFRS 9.

IFRS 15 – Revenue from Contracts with Customers establishes a comprehensive framework for determining whether, how much and when revenue is recognized. It replaces existing revenue recognition guidance, including IAS 18 Revenue, IAS 11 Construction Contracts and IFRIC 13 Customer Loyalty Programs. IFRS 15 is effective for annual reporting periods beginning on or after January 1, 2018 with early adoption permitted. The Company will adopt IFRS 15 using the modified retrospective approach on January 1, 2018. Based on the Company's review of contracts with customers and its assessment of various revenue streams, at this time, the Company is not able to assess the impact that the adoption of IFRS 15 will have on the Company's net income (loss) and financial position. However, the Company is still in the process of reviewing all of its contracts and fully assessing the financial statement impact. The Company does anticipate expanding disclosures in the notes to its consolidated financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue streams by product type.

IFRS 16 – Leases sets out the principles for the recognition, measurement, presentation and disclosure of leases for both parties to a contract, i.e. the customer ('lessee') and the supplier ('lessor') and replaces the previous leases standard, IAS 17 Leases. IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019. The Company is in the early stages of evaluating the impact of IFRS 16 on its consolidated financial statements and the extent of the impact has not yet been determined.

SUBSEQUENT EVENTS

On January 16, 2018 the Company sold 7.933 per cent (7,933 Class A common shares) of its subsidiary, PAEM, to Swala (PAEM) Limited a wholly owned subsidiary of Swala Oil & Gas (Tanzania) plc. ("Swala") for US$25.8 based on an enterprise value of US$325 million as at January 1, 2017 (the "effective date"). After adjusting the enterprise value for long term debt of US$60 million, the net sales price for the 7.933 per cent was US$21.1 million. The consideration received by the Company was US$16.2 million cash (US$17.1 million less a purchase price adjustment of US$0.9 million reflecting Swala's share of cash flow from the effective date of the transaction until closing) and US$4.0 million of Swala convertible preferred shares. The transaction provides Swala with the right to acquire up to 40% of PAEM at the net value of US$265 million adjusted for Swala's share of cash flow from the effective date until the next closing date. The Company has granted an extension of this right to May 11, 2018.

On January 18, 2018 the Company declared a dividend of CDN$0.60 per share on each of its class A voting and class B subordinate voting shares to holders of record as of January 31, 2018 paid on February 7, 2018

SUMMARY QUARTERLY RESULTS

The following is a summary of the results for the Company for the last eight quarters:

Figures in US$'000 except where otherwise stated	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Financial								
Revenue	**8,518**	**12,834**	**14,686**	**15,816**	16,834	18,074	14,859	16,118
Net (loss) income	**(4,684)**	**(34)**	**(622)**	**2,840**	1,048	5,302	1,452	(5,638)
(Loss) earnings per share – basic and diluted *(US$)*	**(0.13)**	**(0.00)**	**(0.02)**	**0.08**	0.03	0.15	0.04	(0.16)
Funds flow from operations [1]	**63**	**4,241**	**4,610**	**5,926**	6,211	10,024	6,772	8,848
Funds flow from operations per share – basic and diluted *(US$)*	**0.01**	**0.12**	**0.13**	**0.17**	0.18	0.29	0.19	0.25
Net cash flows from (used in) operating activities	**12,882**	**14,447**	**12,038**	**8,787**	8,345	6,540	6,237	(1,154)
Net cash flows (utilized) per share – basic and diluted *(US$)*	**0.37**	**0.41**	**0.35**	**0.25**	0.24	0.19	0.18	(0.03)
Operating netback *(US$/mcf)*	**2.26**	**2.94**	**3.44**	**3.34**	3.35	3.31	3.32	3.08
Working capital	**69,575**	**71,129**	**73,854**	**68,112**	71,989	67,635	58,395	56,340
Long-term loan	**58,518**	**58,501**	**58,468**	**58,399**	58,399	58,398	58,368	58,350
Shareholders' equity	**78,731**	**82,426**	**82,407**	**82,982**	80,023	79,152	73,887	72,482
Capital expenditures								
Geological and geophysical and well drilling	**–**	**–**	**3**	**27**	32	26	2,558	13,639
Pipeline and infrastructure	**442**	**477**	**250**	**93**	99	(71)	181	356
Other equipment	**30**	**126**	**97**	**–**	–	–	102	2
Other	**–**	**–**	**–**	**7,352**	–	–	–	–
Total	**472**	**603**	**350**	**7,472**	131	(45)	2,841	13,977
Operating								
Additional Gas sold *(MMcf)*								
– industrial	**1,110**	**1,285**	**1,158**	**1,041**	1,226	1,238	1,151	972
– power	**2,428**	**2,867**	**2,437**	**2,873**	2,895	3,047	2,521	3,241
Total	**3,538**	**4,152**	**3,595**	**3,914**	4,121	4,285	3,672	4,213
Additional Gas sold *(MMcfd)*								
– industrial	**12.1**	**14.0**	**12.7**	**11.6**	13.3	13.5	12.6	10.7
– power	**26.4**	**31.1**	**26.8**	**31.9**	31.5	33.1	27.7	35.6
Total	**38.5**	**45.1**	**39.5**	**43.5**	44.8	46.6	40.3	46.3
Total average price per mcf *(US$)*								
– industrial	**7.78**	**7.65**	**7.69**	**7.75**	7.52	7.60	7.64	8.15
– power	**3.63**	**3.63**	**3.57**	**3.57**	3.57	3.57	3.55	3.55
Weighted average	**4.93**	**4.87**	**4.90**	**4.68**	4.75	4.61	4.83	4.61

[1] *See non-GAAP measures*

PRIOR EIGHT QUARTERS

The general decrease in revenue from Q3 2016 is the consequence of the Company only recognizing a percentage of the TANESCO invoiced amounts for revenue recognition purposes from Q4 2016 onwards. The fall in revenue from Q1 2017 to Q2 2017 is a consequence of the fall in the volume of gas sold to the industrial sector (primarily a consequence of planned and unplanned maintenance work at a cement plant) and to the power sector due to increased hydro utilization. Despite an increase in sales volumes from Q2 2017 to Q3 2017, revenue fell due to a combination of a decrease in the current income tax adjustment and the depletion of the cost pool during the quarter. The revenue fell in Q4 2017 due to the combination of a 15% fall in sales volumes, a substantial increase in TPDC share of Profit Gas and a negative current income tax adjustment.

Changes in net income over the last two years were negatively impacted by the poor payment history of TANESCO. In Q1 2016, Q2 2016 and Q3 2016 doubtful debt provisions of US$8.0 million, US$3.5 million and US$0.9 million respectively were provided against increased TANESCO arrears. Other significant factors affecting the results were:

- Commencing in Q4 2016 the Company recognized a percentage of the TANESCO invoiced amount for revenue recognition purposes in accordance with the revised estimation procedure which resulted in a net revenue reduction of US$1.6 million in both Q4 2016 and Q1 2017, a reduction of US$0.8 million in Q2 2017, a net revenue increase of US$1.8 million in Q3 2017 and a net revenue increase of US$1.0 million in Q4 2017 (see "Operating Revenue").
- The Company recorded an interest expense of US$1.0 million in Q1 2016, US$1.6 million in Q2 to Q4 2016, US$2.3 million in Q1 2017 and Q2 2017, US$2.9 million in Q3 2017 and US$2.6 million in Q4 2017. The increase in 2017 is a result of the participatory interest accrual on the IFC Loan.
- Changes in stock based compensation due to fluctuations in the Company share price and issuance of new RSUs.
    - Q1 2016: Charge of US$2.8 million as a consequence of an increase in the share price from CDN$2.75 at the end of Q4 2015 to CDN$4.14 at the end of Q1 2016.
    - Q2 2016: Credit of US$0.7 million, share price closed at CDN$3.40.
    - Q3 2016: Credit of US$0.1 million, share price closed at CDN$3.41.
    - Q4 2016: Charge of US$0.6 million, share price closed at CDN$3.82.
    - Q1 2017: Charge of US$0.8 million predominately a consequence of the issuance of 259,067 RSUs which vested fully on the date of grant. The share price closed at CDN$3.85.
    - Q2 2017: Charge of US$1.6 million predominately the consequence of the issuance of 1,143,255 RSUs. The share price closed at CDN$4.01.
    - Q3 2017: Charge of US$2.1 million, share price closed at CDN$4.60.
    - Q4 2017: Charge of US$2.1 million, share price closed at CDN$5.00

Management's Discussion & Analysis

Differences in funds flow from operations for the last seven quarters were primarily a result of changes in revenue during the periods. The decrease in funds flow from operations in Q4 2016 from Q3 2016 is a consequence of expensing indirect taxes associated with invoices that have not been recorded in the financial statements because they do not meet the revenue recognition criteria with respect to assurance of collectability. The increase in the funds flow from operations to US$10.0 million in Q3 2016 from US$6.7 million in Q2 2016 is primarily the result of the US$3.2 million increase in revenue over the quarter. The difference in funds flow from operations between Q1 2017 and Q1 2016 is primarily a consequence of US$1.0 million paid in stock based compensation in Q1 2017 (Q1 2016: US$ nil). The fall in funds flow from operations between Q1 2017 to Q2 2017 is a consequence of the decline in revenue due to a decline in gas sales volumes and the associated fall in the Company's share of Profit Gas. The fall in funds flow from operations between Q2 2016 and Q2 2017 is primarily a result of the fall in the Company's operating revenue as a consequence of the change in the TANESCO revenue recognition criteria together with lower Additional Gas volumes and associated Profit Gas entitlement. The decrease in funds flow from operations between Q2 2017 and Q3 2017 is a consequence of several factors, most notably the decrease in the loss between the periods being offset by the non-cash movements associated with stock based compensation and taxation. The decrease in funds flow from operations between Q3 2016 and Q3 2017 is primarily a consequence of the fall in revenue between the periods. The decrease in cashflow from operations between Q4 2017 and Q4 2016 is a consequence of the fall in revenue together with an increase in general and administrative costs. The decrease between Q4 2017 and Q3 2017 is the consequence of the fall in revenue, the increase in general administrative costs offset by a lower recovery of deferred taxation in the period.

Changes in net cash flows from operating activities between quarters were primarily a result of the timing and amount of payments received from TANESCO.

The progressive increase in working capital from Q1 2016 to Q4 2016 is mainly the result of US$21.1 million in net cash flows from operating activities being offset by US$3.0 million of capital expenditure over the same period given the Company's reduced level of drilling and related activity. Between Q4 2016 and Q3 2017 the level of working capital has remained fairly consistent at an average of US$71.3 million. The fall in working capital to US$69.6 million in Q4 2017 from US$71.1 million in Q3 2017 is the consequence of the increased liabilities associated with the IFC loan and TPDC share of Profit Gas, offsetting the increased collections from TANESCO.

Capital expenditure for the last four quarters amounted to US$1.5 million compared to US$16.9 million from Q1 2016 to Q4 2016. The capital additions in Q1 2017 were primarily a result of the transfer of the Songas share of workover costs incurred in 2015 to property, plant and equipment. The workover and drilling program commenced in Q3 2015 and was completed at the end of the second quarter 2016.

The level of Industrial sales volumes in the four quarters ending Q4 2017 averaged of 1,149 MMcf (four quarters ending Q4 2016: 1,147 MMcf) with total Industrial sales volumes for the four quarters ending Q4 2017 increasing to 4,594 MMcf (12.6 MMcfd) compared to 4,587 MMcf (12.6 MMcfd) in the four quarters ending Q4 2016.

The level of Power sales volumes decreased by 9% in the four quarters ending Q4 2017 to an average of 2,652 MMcf (four quarters ending Q4 2016: 2,926 MMcf) with total Power sector sales volumes for the four quarters ending Q4 2017 decreasing to 10,605 MMcf (29.1 MMcfd) compared to 11,704 MMcf (32.1 MMcfd) in the four quarters ending Q4 2016. The decline is the consequence of lower offtakes by TANESCO and unscheduled maintenance at the Songo Ubungo Power generation facility.

SELECTED FINANCIAL INFORMATION

Selected annual financial information derived from the audited consolidated financial statements for the years ended December 31, 2017, 2016 and 2015 is set out below:

Figures in US$'000 except per share amount	**2017**	2016	2015
Revenue	**51,854**	65,885	54,088
Net cash flows from operating activities	**48,154**	19,968	7,018
Funds flow from operations [(1)]	**14,840**	31,855	26,454
Net (loss) income	**(2,500)**	2,164	1,533
Total assets	**249,549**	221,130	189,683
(Loss) earnings in US$ per share:			
Basic and diluted	**(0.07)**	0.06	0.04

[(1)] *See Non-GAAP measures*

Revenue decreased by 21% to US$51.9 million in 2017 from US$65.9 million in 2016. The decrease is primarily a consequence of recording revenue based on the expected collectability approach, a 7% fall in sales volume and the Company being entitled to 72% of the net field revenue in 2017 compared to 85% in 2016 due to the depletion of the costs pools after the recovery of the expenditure associated with the Offshore Development Program. As a result, TPDC share of revenue increased to US$17.6 million in 2017 from US$9.8 million in 2016.

The decrease in revenue was the primary factor in the 53% decrease in the funds flow from operations to US$14.8 million (2016: US$31.9 million). The net cash flows from operating activities increased by 141% to US$48.2 million (2016: US$20.0 million) which was primarily the result of increased collections from TANESCO.

BUSINESS RISKS

Financing

The ability of the Company to meet its financing obligations or to arrange financing in the future will depend in part upon the prevailing capital market conditions as well as the business performance of the Company. There can be no assurance that the Company would be successful in its efforts to meet its current commitments or arrange additional financing on terms satisfactory to the Company. If additional financing is raised by the issuance of shares from treasury of the Company, control of the Company may change and shareholders may suffer additional dilution.

From time to time the Company may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed partially or wholly with debt, which may temporarily increase the Company's debt levels above industry standards.

Collectability of Receivables

The Company evaluates the collectability of its receivables on the basis of payment history, frequency and predictability, as well as Management’s assessment of the customer’s willingness and ability to pay. The Company has been impacted by TANESCO’s inability to pay for current deliveries and pay down arrears.

Prior to 2016 the Company had reached an understanding with TANESCO that the Company would continue to supply gas if TANESCO remained reasonably current with payments for gas deliveries. Up to September 30, 2016 the Company recorded revenue from TANESCO based on volumes delivered, however, TANESCO payments were inconsistent and not always in compliance with the agreed understanding. This resulted in the Company recording provisions for doubtful accounts for amounts outstanding from TANESCO for more than 60 days. Commencing on October 1, 2016, the Company began recording revenues for sales to TANESCO based on the expected amount to be collected, which represents a percentage of the amounts invoiced to TANESCO determined by comparison of TANESCO’s payment history to the amounts invoiced by the Company over the previous three years. Management believes this approach provides the best estimate of TANESCO’s ability to pay and remain reasonably current and as well reflects the economic reality of the situation.

Cash received in excess of the revenue recorded from TANESCO in any given period will be recorded as deferred revenue. In periods when the deferred revenue balance is greater than the average amounts invoiced to TANESCO for gas deliveries for the previous four quarters, any amount in excess of the four quarter average will be recorded as current period revenue to the extent there is unrecognized revenue resulting from the approach to revenue recognition adopted on October 1, 2016. If such unrecognized revenue is reduced to nil, additional amounts collected in excess of the quarterly average will be applied to pay the oldest TANESCO invoice recorded and previously provided for.

In periods when cash received is less than revenue recorded, the deferred revenue will be reduced accordingly. If the deferred revenue amount is reduced to nil, the difference will be recorded as accounts receivable.

The percentage used to recognize TANESCO revenue will be reviewed on at least a semi-annual basis, more frequently if circumstances require and if there is a significant difference between the amount of revenue recorded and amounts received, the percentage used to record revenue as well as any existing receivable or deferred revenue balance will be revised accordingly. The percentage was increased effective October 1, 2017 to reflect the most recent three year payment history for TANESCO compared to amounts invoiced for deliveries.

At December 31, 2017 the current receivable from TANESCO was US$ nil (December 31, 2016: US$5.7 million). During the year the amounts received from TANESCO were in excess of the revenue recognized for gas sales to TANESCO resulting in a deferred revenue balance of US$8.4 million (December 31, 2016: US$ nil), after the reallocation of US$3.8 million to net field revenue during Q4 2017.

The long-term trade receivable at December 31, 2017 and 2016 was US$74.4 million (provision of US$74.4 million). Subsequent to December 31, 2017 the Company has invoiced TANESCO US$6.2 million for 2018 gas deliveries and TANESCO has paid the Company US$10.0 million.

As at December 31, 2017 Songas owed the Company US$8.2 million (2016: US$23.3 million) while the Company owed Songas US$2.0 million (2016: US$2.3 million). The amounts due to the Company are mainly for sales of gas of US$2.4 million (2016: US$2.2 million) and for the operation of the gas plant of US$5.8 million (2016: US$6.6 million) against which the Company has made a provision for doubtful accounts of US$4.9 million (2016: US$4.9 million) whereas the amounts due to Songas primarily relate to pipeline tariff charges of US$1.7 million (2016: US$1.9 million). The operation of the gas plant is conducted at cost and the charges are billed to Songas on a flow through basis

Operating Hazards and Uninsured Risks

The business of the Company is subject to all of the operating risks normally associated with the exploration for, and the production, storage, transportation and marketing of oil and gas. These risks include blowouts, explosions, fire, gaseous leaks, downhole design and integrity, migration of harmful substances and oil spills, any of which could cause personal injury, result in damage to, or destruction of, oil and gas wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations. In addition, all of the Company's operations will be subject to the risks normally incident to drilling of natural gas wells and the operation and development of gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blowouts, equipment and tubing failures and other accidents, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks. Drilling conducted by the Company overseas will involve increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. The impact that any of these risks may have upon the Company is increased due to the fact that the Company currently only has one producing property. The Company maintains insurance against some, but not all potential risks. There can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavourable event not fully covered by insurance could have a material adverse effect on the Company's financial condition, results of operations and cash flows.

Furthermore, the Company cannot predict whether insurance will continue to be available at a reasonable cost, or at all.

Foreign Operations

The Company's operations and related assets are located in Italy and Tanzania which may be considered to be politically and/or economically unstable. Exploration or development activities in Tanzania and Italy may require protracted negotiations with host governments, national oil companies and third parties and are frequently subject to economic and political considerations, such as, the risks of war, actions by terrorist or insurgent groups, expropriation, nationalization, creeping nationalization, renegotiation or nullification of existing contracts and production sharing agreements, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls and foreign governmental regulations that favour or require the awarding of drilling and construction contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. In addition, if a dispute arises with foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts.

In Tanzania the state retains ownership of the minerals and consequently retains control of, the exploration and production of hydrocarbon reserves. Accordingly, these operations may be materially affected by the Government through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges. The Government of Tanzania issued a National Natural Gas Policy in 2013 that contemplates greater government control over the industry and in some areas conflicts with the Company's rights under the Songo Songo PSA. This policy was confirmed with the passing of the Petroleum Act in 2015. The Petroleum Act does provide grandfathering provisions upholding the rights of the Company under their PSA as it was signed prior to passing of the Petroleum Act. However, it is still unclear how the provisions of the Petroleum Act will be interpreted and implemented regarding upstream and downstream activities. There can be no assurance that the rights of the Company under the PSA will be grandfathered with respect to any future natural gas legislation.

The Company's development properties and its current proved natural gas reserves located offshore on the Songo Songo Island in Tanzania are subject to regulation and control by the Government of Tanzania. Primarily operations are regulated by national and parastatal organizations including the energy regulators (PURA and EWURA), and TPDC. The Company and its predecessors have operated in Tanzania for a number of years and believe that it has had reasonably good relations with the current Tanzanian Government. However, there can be no assurance that present or future administrations or governmental regulations in Tanzania will not materially adversely affect the operations or future cash flows of the Company.

Tanzania ranks 103 out of 180 on the 2017 Transparency International Corruption Index (2016: 116 out of 176). At the end of 2014 there was a significant corruption scandal in Tanzania's energy sector involving a number of senior government officials, including senior officials from the Ministry of Energy and Minerals (now the ME). Having assessed the Company's exposure to corruption in Tanzania, it was concluded that the risk of the Company and/or its subsidiaries violating applicable laws prohibiting corrupt activities are mitigated or unlikely given the Company's controls relating to such risks and their effective operation. There can be no assurance that corruption may not indirectly affect or otherwise impair the Company's ability to operate in Tanzania and effectively pursue its business plan in that country.

Management's Discussion & Analysis

The TRA is responsible for the collection of taxes in Tanzania. TRA is not party to the Songo Songo PSA and there is no assurance that the TRA will consider itself bound by its terms. Accordingly, there is a risk that the TRA will take interpretations of issues distinct from the PSA, resulting in assessments, penalties and fines which have not been contemplated by the Company, and in additional costs which are not recoverable under the PSA. The TRA has significant powers in Tanzania and is capable of causing the Company's operations in that country to cease.

The Company requires additional gas processing and transportation infrastructure to allow additional development and the ultimate monetization of the Company's reserves through additional gas sales. The Government of Tanzania has completed the US$1.2 billion NNGIP that comprises two gas processing plants, one being at Songo Songo, and a pipeline to transport gas from Southern Tanzania to Dar es Salaam. The Company is currently negotiating terms for the sale of incremental gas volumes through the NNGIP with TPDC however there is no assurance that an agreement will be reached on terms acceptable to the Company.

Access to Songas processing and transportation

Although the Company operates the Songas gas processing plant, Songas is the owner of the plant and the 16-inch pipeline system which transports natural gas from Songo Songo to Dar es Salaam. The Company's ability to deliver gas to its customers in Dar es Salaam is dependent upon it having access to the Songas infrastructure. Although there are agreements with Songas to allow the Company to process and transport gas, there is no assurance that these rights could not be challenged or curtailed by Songas. The inability to access the Songas plant and processing facilities would materially impair the Company's ability to realize revenue from natural gas sales.

As a result of the Ubungo power plant re-rating that occurred in 2011, pursuant to the Re-Rating Agreement, the capacity of the Songas gas processing plant was increased to a maximum of 110 MMcfd (restricted to 102 MMcfd because of pipeline and pressure requirements). The Re-Rating Agreement expired in 2013 and no new agreement is currently in place. Without the Re-Rating Agreement Songas, the owner of the gas processing plant, may require the plant to be operated at its original capacity of 70 MMcfd which would result in a material reduction in the Company's sales volumes. This risk has been significantly mitigated with the recent signing of AGP2 which acknowledges that production from the Songas facility is to continue based on the increased re-rated capacity.

Recent Legislation

The Petroleum Act, passed in 2015, repealed earlier legislation and provides a regulatory framework over upstream, mid-stream and downstream gas activity and consolidates and puts in place a comprehensive legal framework for regulating the oil and gas industry in the country. The Petroleum Act also provides for the creation of an upstream regulator, the Petroleum Upstream Regulatory Authority ("PURA"). The mid and downstream oil and gas activities are proposed to be regulated by the current authority, the Energy and Water Utilities Regulatory Authority ("EWURA"). The Petroleum Act also confers upon on TPDC, the status of the National Oil Company, mandated with the task of managing the country's commercial interest in petroleum operations as well as mid and downstream natural gas activities. The Petroleum Act vests TPDC with exclusive rights in the entire petroleum upstream and the natural gas mid and downstream value chains. However, the exclusive rights of TPDC do not extend to mid and downstream petroleum supply operations. The Petroleum Act does provide grandfathering provisions upholding the rights of the Company under their PSA as it was signed prior to passing of the Petroleum Act.

On October 7, 2016 the Government of Tanzania (the "GoT") issued the Petroleum (Natural Gas Pricing) Regulation made under Sections 165 and 258 (I) of the Petroleum Act. Under the Petroleum Act, Article 260 (3) preserves the Company's pre-existing right with TPDC to market and sell Additional Gas together or independently on terms and conditions (including prices) negotiated with third party natural gas customers.

On July 15, 2017 the GoT passed into law the Natural Wealth and Resources (Permanent Sovereignty) Act, 2017, the Written Laws (Miscellaneous Amendments) Act, 2017, and The Natural Wealth and Resources Contracts (Review and Re-Negotiation of Unconscionable Terms) Act, 2017. The first and second of these acts are forward looking and only apply to agreements entered into on or after July 15, 2017. These acts contain new regulations including but not limited to regulations that all arbitration processes must be heard within Tanzania and restrict the ability to move funds out of Tanzania. The third act is rearward looking and provides the right of the GoT to renegotiate contract clauses that are deemed to have unconscionable terms.

It is still unclear how the provisions of the Petroleum Act and legislation will be enacted and implemented and the Company is uncertain regarding the potential impact on its business in Tanzania.

Amended and Restated Gas Agreement

The ARGA provides clarification of the Protected Gas volumes and removes all terms dealing with the security of the Protected Gas and contract terms dealing with the consequences of any insufficiency are dealt with in a proposed Insufficiency Agreement ("IA"). The ARGA was initialed by all parties but both the ARGA and IA remain unsigned as at the date of this report. In certain respects, the parties thereto are conducting themselves as though the ARGA is in effect however no formal agreement has been reached on providing additional security in the event of an insufficiency of Protected Gas. The Company is actively monitoring the reservoir and, supported by the report of its independent engineers, does not anticipate that a liability will occur in this respect. Management does not foresee a material risk with the conduct of the Company's business with an unsigned ARGA or IA at this time.

Industry Conditions

The oil and gas industry is intensely competitive and the Company competes with other companies which possess greater technical and financial resources. Many of these competitors not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum, natural gas products and other products on an international basis. Oil and gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and invasion of water into producing formations. Currently, the Company operates the Songo Songo natural gas property. The Company has the right to earn an interest in a permit in Italy; however, changes in Italian environmental legislation in late 2015 have resulted in the development of the licence being postponed indefinitely. There is a risk that in the future either the operatorship could change and the property operated by third parties, or operations may be subject to control by national oil companies, Songas, or parastatal organizations and, as a result, the Company may have limited control over the nature and timing of exploration and development of such properties, or the manner in which operations are conducted on such properties.

The marketability and price of natural gas which may be acquired, discovered or marketed by the Company will be affected by numerous factors beyond its control. The natural gas market in Tanzania is in development and there is currently limited access to infrastructure with which to serve potential new markets beyond that being constructed by the Company, Songas and TPDC, which now includes the NNGIP. The ability of the Company to market any natural gas from current or future reserves in Tanzania may depend upon its ability to develop natural gas markets in Tanzania and the surrounding region, obtain access to the necessary infrastructure to process gas and to deliver sales gas volumes, including acquiring capacity on pipelines which deliver natural gas to commercial markets. The Company is also subject to market fluctuations in the prices of oil and natural gas, uncertainties related to the delivery and proximity of its reserves to pipelines and processing facilities and extensive government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business. The Company is also subject to a variety of waste disposal, pollution control and similar environmental laws.

The oil and natural gas industry is subject to varying environmental regulations in each of the jurisdictions in which the Company may operate. Environmental regulations place restrictions and prohibitions on emissions of various substances produced concurrently and oil and natural gas and can impact on the selection of drilling sites and facility locations, potentially resulting in increased capital expenditures.

Management's Discussion & Analysis

Additional Gas

The Company has the right under the terms of the PSA to market volumes of Additional Gas subject to satisfying the requirements to deliver Protected Gas to Songas.

There is a risk that Songas could interfere in the Company's ability to produce, transport and sell volumes of Additional Gas if the Company's obligations to Songas under the Gas Agreement are not met. In particular, Songas has the right in specific circumstances to request reasonable security on all Additional Gas sales.

With the enactment of the Petroleum Act, TPDC was given significant rights over upstream and downstream operations in the country and is the sole aggregator of natural gas in the country. The Petroleum Act recognizes the rights of the Company pursuant to the PSA; however, some clauses conflict with the Company's rights to directly market Additional Gas, and there is a risk that this prior right will not continue to be recognized and that the Company's ability to maximize revenue on Additional Gas sales may be impaired by the requirement to sell gas to TPDC as aggregator.

Replacement of Reserves

The Company's natural gas reserves and production and, therefore, its cash flows and earnings are highly dependent upon the Company developing and increasing its current reserve base and discovering or acquiring additional reserves. Without the addition of reserves through exploration, acquisition or development activities, the Company's reserves and production will decline over time as reserves are depleted. To the extent that funds flow from operations is insufficient and external sources of capital become limited or unavailable, the Company's ability to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. There can be no assurance that the Company will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs.

Asset Concentration

The Company's natural gas reserves are currently limited to one producing property, the Songo Songo field, and the productive potential from this field is limited. There is no assurance that the Company will have sufficient deliverability through the existing wells to provide additional natural gas sales volumes, and that there may be significant capital expenditures associated with any remedial work, workovers, or new drilling required to achieve deliverability. In addition, any difficulties relating to the operation or performance of the field would have a material adverse effect on the Company. Until the Company is able to deliver gas through the NNGIP, it has no redundant capacity in the production facilities or pipeline. A loss or material reduction in production capabilities will have a material adverse effect on the total production and funds flow from operating activities of the Company. The Company has an interest in the Elsa licence in Italy however changes in Italian environmental legislation in late 2015 have resulted in the development of the Elsa Italian licence being postponed indefinitely.

Environmental and Other Regulations

Extensive national, state, and local environmental laws and regulations in foreign jurisdictions will affect nearly all of the Company's operations. These laws and regulations set various standards regulating certain aspects of health and environmental quality, provide for penalties and other liabilities for the violation of such standards and establish in certain circumstances obligations to remediate current and former facilities and locations where operations are or were conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation. There can be no assurance that the Company will not incur substantial financial obligations in connection with environmental compliance. Significant liability could be imposed on the Company for damages, cleanup costs or penalties in the event of certain discharges into the environment, environmental damage caused by previous owners of property purchased by the Company or non-compliance with environmental laws or regulations. Such liability could have a material adverse effect on the Company. Moreover, the Company cannot predict what environmental legislation or regulations will be enacted in the future or how existing or future laws or regulations will be administered or enforced. Compliance with more stringent laws or regulations, or more vigorous enforcement policies of any regulatory authority, could in the future require material expenditures by the Company for the installation and operation of systems and equipment for remedial measures, any or all of which may have a material adverse effect on the Company. As party to various licences, the Company may have an obligation to restore producing fields to a condition acceptable to the authorities at the end of their commercial lives. The PSA does not contain abandonment obligations for the Company. In addition, the Company expects the Songo Songo field to produce well beyond the term of the current licence.

The Company's petroleum and natural gas operations are subject to extensive governmental legislation and regulation and increased public awareness concerning environmental protection.

While management believes that the Company is currently in compliance with environmental laws and regulations applicable to the Company's operations in Tanzania and Italy, no assurances can be given that the Company will be able to continue to comply with such environmental laws and regulations without incurring substantial costs.

In accordance with the terms of the PSA, no provision has been recognized for future decommissioning costs in Tanzania as it is forecast that there will still be commercial gas reserves when the Company relinquishes the licence in 2026. The Company expects that the cost of complying with environmental legislation and regulations will increase in the future. Compliance with existing environmental legislation and regulations has not had a material effect on capital expenditures, earnings or competitive position of the Company to date. Although management believes that the Company's operations and facilities are in material compliance with such laws and regulations, future changes in these laws, regulations or interpretations thereof, or the nature of its operations, may require the Company to make significant additional capital expenditures to ensure compliance in the future.

Volatility of Oil and Gas Prices and Markets

The Company's financial condition, operating results and future growth will be dependent on the prevailing prices for its natural gas production. Historically, the markets for oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes to the demand for oil and natural gas, whether the result of uncertainty or a variety of additional factors beyond the control of the Company. Any substantial decline in the prices of oil and natural gas could have a material adverse effect on the Company and the level of its natural gas reserves. Additionally, the economics of producing from some wells may change as a result of lower prices, which could result in a suspension of production by the Company.

No assurance can be given that oil and natural gas prices will be sustained at levels which will enable the Company to operate profitably. From time to time the Company may avail itself of forward sales or other forms of hedging activities with a view to mitigating its exposure to the risk of price volatility.

There has been a significant increase in exploration activity in Tanzania, which has yielded world class discoveries of natural gas that could, when developed, lead to increased competition for gas markets and lower gas prices in the future.

In addition, various factors, including the availability and capacity of oil and gas gathering systems and pipelines, the effect of foreign regulation of production and transportation, general economic conditions, changes in supply due to drilling by other producers and changes in demand may adversely affect the Company's ability to market its gas production.

Uncertainties in Estimating Reserves and Future Net Cash Flows

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and cash flows to be derived therefrom, including many factors beyond the control of the Company. The reserve and cash flow information contained herein represents estimates only. The reserves and estimated future net cash flow from the Company's properties have been independently evaluated by McDaniel & Associates Consultants Ltd. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, crude oil price differentials to benchmarks, future prices of oil and natural gas, operating costs, transportation costs, cost recovery provisions and royalties, TPDC "back-in" methodology and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date of the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material.

Title to Properties

Although title reviews have been done and will continue to be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Company which could result in a reduction of the revenue received by the Company.

Acquisition Risks

The Company intends to acquire natural gas infrastructure and possibly additional oil and gas properties. Although the Company performs a review of the acquired properties that it believes is consistent with industry practices, such reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, the Company will focus its due diligence efforts on the higher valued properties and will sample the remainder. However, even an in depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not be performed on every well, and structural or environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. The Company may be required to assume pre-closing liabilities, including environmental liabilities, and may acquire interests in properties on an "as is" basis. There can be no assurance that the Company's acquisitions will be successful.

Reliance on Key Personnel

The Company is highly dependent upon its executive officers and key personnel. The unexpected loss of the services of any of these individuals could have a detrimental effect on the Company. The Company does not maintain key life insurance on any of its employees or officers.

Controlling Shareholder

W David Lyons, the Company's Chairman, and Chief Executive Officer is the beneficial controlling shareholder of the Company and holds approximately 99.6% of the outstanding Class A shares and approximately 16.5% of the Class B shares. Consequently, Mr. Lyons is the beneficial holder of approximately 20.7% of the equity (20.7% fully diluted) and controls 59.2% of the total votes of the Company.

CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The following are the critical judgements, apart from those involving estimations (see below), that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the accounts recognized in these consolidated financial statements.

Critical judgements in applying accounting policies:

A. Exploration and evaluation assets and property, plant and equipment

The Company assesses its property, plant and equipment for impairment when events or circumstances indicate that the carrying amount of its assets may not be recoverable. If any indication of impairment exists, the Company performs an impairment test on the Cash Generating Unit ("CGU"), which is the lowest level at which there are identifiable cash flows. The carrying amount of the CGU is compared to its recoverable amount which is defined as the greater of its fair value less cost to sell and value in use and is subject to management estimates. These estimates include quantities of reserves and future production, future commodity pricing, development costs, operating costs, and discount rates. Any changes in these estimates may have an impact on the recoverable amount of the CGU.

Property, plant and equipment is measured at cost less accumulated depreciation, depletion and amortization. The Company's oil and natural gas properties are depleted using the unit-of-production method over proved plus probable reserves. The unit-of-production method takes into account estimates of capital expenditures incurred to date along with future development capital required to develop both proved plus probable reserves.

B. Collectability of receivables

The Company evaluates the collectability of its receivables on the basis of payment history, frequency and predictability, as well as Management's assessment of the customer's willingness and ability to pay. Management performs impairment tests each period on the Company's current and long-term receivables. As a result of TANESCO's inability to fully pay all amounts invoiced by the Company for the past few years, management of the Company has modified its approach to revenue recognition as it relates to TANESCO only. Commencing on October 1, 2016, the Company began recording revenues for sales to TANESCO based on the expected amount to be collected which represents a percentage of the amounts invoiced to TANESCO determined by comparison of TANESCO's historical payment history to the amounts invoiced by the Company over the previous three years. Management believes this approach provides the best estimate of TANESCO's ability to pay and remain reasonably current and as well reflects the economic reality of the situation.

The percentage used to recognize TANESCO revenue will be reviewed as circumstances require and if there is a significant difference between the amount of revenue recorded and amounts received, the percentage used to record revenue as well as any existing receivable or deferred revenue balance will be revised accordingly.

C. Taxes

The Company operates in a jurisdiction with complex tax laws and regulations, which are evolving over time. The Company has taken certain tax positions in its tax filings and these filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax impact may differ significantly from that estimated and recorded by management.

Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period in which the change occurs.

Management's Discussion & Analysis

Key sources of estimation of uncertainty

D. Reserves and Additional Profits Tax

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and cash flows to be derived therefrom, including many factors beyond the control of the Company. The reserve and cash flow information contained herein represents estimates only and are used to estimate APT by forecasting the total APT payable in the future as a proportion of the forecast Profit Gas over the term of PSA licence. The actual APT to be paid is dependent on the achieved value of the Additional Gas sales and the quantum and timing of the operating costs and capital expenditure program. The reserves and estimated future net cash flow from the Company's properties have been evaluated by independent petroleum engineers. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, crude oil price differentials to benchmarks, future prices of oil and natural gas, operating costs, transportation costs, cost recovery provisions and royalties, TPDC "back-in" methodology and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date of the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. For the purpose of the reserves certification as at December 31, 2017 it was assumed that TPDC will elect to 'back-in' for 20% for all future new drilling activities after well SS-12 and this is reflected in the Company's net reserve position. As at the time of writing this report TPDC have made no such election.

Reserves are integral to the amount of depletion recognized and impairment test.

E. Fair value of stock based compensation

All stock options issued or stock appreciation rights granted by the Company are required to be valued at their fair value. In assessing the fair value of the equity based compensation, estimates have to be made as to (i) the volatility in share price, (ii) the risk free rate of interest, and (iii) the level of forfeiture. In the case of stock options, this fair value is estimated at the date of issue and is not revalued, whereas the fair value of stock appreciation rights is recalculated at each reporting period.

F. Cost recovery

The Company is able to recover reasonable costs incurred on the development of the Songo Songo project out of 75% of the gross revenues less processing and pipeline tariffs ("Net Revenue"). There are inherent uncertainties in estimating when costs have been recovered as these costs are subject to government audit and in exceptional circumstances a potential reassessment after the elapse of a considerable period of time.

G. Financial instrument classification and measurement

The Company classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including expected interest rate, share prices, and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuation in this level are those with inputs for the asset or liabilities that are not based on observable market data.

ORCA EXPLORATION GROUP INC.

2017 FINANCIAL STATEMENTS & NOTES

Management's Report to Shareholders

The accompanying consolidated financial statements of Orca Exploration Group Inc. are the responsibility of Management. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

The consolidated financial statements have been prepared by Management, on behalf of the Board, in accordance with the accounting policies disclosed in the notes to the consolidated financial statements. Where necessary, management has made informed judgments and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the consolidated financial statements have been prepared within acceptable limits of materiality and are in accordance with International Financial Reporting Standards appropriate in the circumstances.

Management, with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures and has concluded that such disclosure controls and procedures are effective.

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are properly authorized, assets are safeguarded and financial records are properly maintained to provide reliable information for the preparation of financial statements. An independent firm of Chartered Professional Accountants, as appointed by the Shareholders, audited the consolidated financial statements in accordance with the Canadian Generally Accepted Auditing Standards to enable them to express an opinion on the fairness of the consolidated financial statements in accordance with International Financial Reporting Standards.

The Board of Directors carries out its responsibility for the financial reporting and internal controls of the Company principally through an Audit Committee. The committee has met with the independent auditors and Management in order to determine if Management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

W. David Lyons
Chairman and Chief Executive Officer

April 13, 2018

Blaine Karst

Blaine E. Karst
Chief Financial Officer

April 13, 2018

Independent Auditors' Report

To the Shareholders of Orca Exploration Group Inc.

We have audited the accompanying consolidated financial statements of Orca Exploration Group Inc., which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, the consolidated statements of comprehensive (loss) income, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Orca Exploration Group Inc. as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants

April 13, 2018
Calgary, Canada

Consolidated Statements of Comprehensive (Loss) Income

ORCA EXPLORATION GROUP INC. **YEARS ENDED DECEMBER 31**

US$'000	Note	2017	2016
Revenue	*6, 7*	**51,854**	65,885
Production and distribution		**(3,629)**	(4,033)
Net production revenue		**48,225**	61,852
Operating expenses			
General and administrative		**(20,808)**	(16,337)
Depletion		**(8,678)**	(9,191)
Operating income		**18,739**	36,324
Finance income		**366**	383
Finance expense	*9*	**(12,831)**	(19,937)
Income before tax		**6,274**	16,770
Income tax expense – current	*10*	**(7,873)**	(9,719)
Income tax recovery (expense) – deferred	*10*	**1,162**	(3,661)
Additional Profits Tax	*11*	**(2,063)**	(1,226)
Net (loss) income		**(2,500)**	2,164
Foreign currency translation gain (loss) from foreign operations		**216**	(295)
Comprehensive (loss) income		**(2,284)**	1,869
Net (loss) income per share *(US$)*			
Basic and diluted	*17*	**(0.07)**	0.06

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Financial Position

ORCA EXPLORATION GROUP INC.		AS AT DECEMBER 31	
US$'000	Note	**2017**	2016
Assets			
Current assets			
Cash and cash equivalents		**122,322**	80,895
Trade and other receivables	*12*	**12,273**	27,638
Prepayments		**866**	651
		135,461	109,184
Non-current assets			
Long-term trade and other receivables	*12*	**2,797**	525
Property, plant and equipment	*13*	**111,291**	111,421
		114,088	111,946
Total Assets		**249,549**	221,130
Equity and liabilities			
Current liabilities			
Trade and other payables	*14*	**56,758**	34,305
Tax payable		**718**	2,890
Deferred revenue	*12*	**8,410**	–
		65,886	37,195
Non-current liabilities			
Deferred income taxes	*10*	**11,811**	12,973
Long-term loan	*15*	**58,518**	58,399
Additional Profits Tax	*11*	**34,603**	32,540
		104,932	103,912
Total Liabilities		**170,818**	141,107
Equity			
Capital stock	*16*	**86,508**	85,488
Contributed surplus		**6,319**	6,347
Accumulated other comprehensive loss		**(165)**	(381)
Accumulated loss		**(13,931)**	(11,431)
		78,731	80,023
Total equity and liabilities		**249,549**	221,130

See accompanying notes to the consolidated financial statements.

Nature of Operations (Note 1); Contractual obligations and committed capital investment (Note 19); Contingencies (Note 20); Subsequent events (Note 23). The consolidated financial statements were approved by the Board of Directors on April 13, 2018.

Director

Director

Consolidated Statements of Cash Flows

ORCA EXPLORATION GROUP INC		YEARS ENDED DECEMBER 31	
US$'000	Note	**2017**	2016
Operating activities			
Net (loss) Income		**(2,500)**	2,164
Adjustment for:			
Depletion and depreciation	*13*	**9,027**	9,777
Provision for doubtful accounts and indirect tax	*9*	**2,956**	14,245
Stock-based compensation	*16*	**4,717**	1,604
Deferred income taxes (recovery) expense	*10*	**(1,162)**	3,661
Additional Profits Tax	*11*	**2,063**	1,226
Unrealized gain on foreign exchange		**(261)**	(822)
Interest expense	*9*	**6,250**	5,668
Participatory interest	*9*	**3,809**	–
Change in non-cash operating working capital	*22*	**23,255**	(17,555)
Net cash flows from operating activities		**48,154**	19,968
Investing activities			
Property, plant and equipment expenditures	*13*	**(1,545)**	(16,924)
Change in non-cash working capital		**(138)**	(10,685)
Net cash used in investing activities		**(1,683)**	(27,609)
Financing activities			
Interest paid	*9*	**(6,250)**	(5,668)
Increase in long-term loan	*15*	**–**	39,800
Proceeds from exercise of options		**992**	–
Net cash flow (used in) from financing activities		**(5,258)**	34,132
Increase in cash		**41,213**	26,491
Cash and cash equivalents at the beginning of the period		**80,895**	53,797
Effect of change in foreign exchange on cash for the period		**214**	607
Cash and cash equivalents at the end of the period		**122,322**	80,895

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

ORCA EXPLORATION GROUP INC.

US$'000	**Capital stock**	**Contributed surplus**	**Cumulative translation adjustment**	**Accumulated loss**	**Total**
Note	*16*				
Balance as at January 1, 2017	85,488	6,347	(381)	(11,431)	80,023
Exercise stock option	1,020	(28)	–	–	992
Foreign currency translation adjustment on foreign operations	–	–	216	–	216
Net loss	–	–	–	(2,500)	(2,500)
Balance as at December 31, 2017	**86,508**	**6,319**	**(165)**	**(13,931)**	**78,731**

US$'000	**Capital stock**	**Contributed surplus**	**Cumulative translation adjustment**	**Accumulated loss**	**Total**
Note	*16*				
Balance as at January 1, 2016	85,488	6,347	(86)	(13,595)	78,154
Foreign currency translation adjustment on foreign operations	–	–	(295)	–	(295)
Net income	–	–	–	2,164	2,164
Balance as at December 31, 2016	85,488	6,347	(381)	(11,431)	80,023

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

General Information

Orca Exploration Group Inc. was incorporated on April 28, 2004 under the laws of the British Virgin Islands with registered offices located at PO Box 146, Road Town, Tortola, British Virgin Islands, VG110. The Company produces and sells natural gas to the power and industrial sectors in Tanzania.

The consolidated financial statements of the Company as at and for the year ended December 31, 2017 comprise accounts of the Company and all its wholly owned subsidiaries (collectively, the “Company” or “Orca Exploration”) and were authorized for issue in accordance with a resolution of the directors on April 10, 2018.

1 NATURE OF OPERATIONS

The Company’s principal operating asset is an interest held by a subsidiary, PanAfrican Energy Tanzania Limited (“PAET”) in a Production Sharing Agreement (“PSA”) with the Tanzania Petroleum Development Corporation (“TPDC”) and the Government of Tanzania (“GoT”) in the United Republic of Tanzania. This PSA covers the production and marketing of certain gas from the Songo Songo Block offshore Tanzania.

The PSA defines gas in the Songo Songo field as “Protected Gas” and “Additional Gas”. The “Protected Gas” is owned by TPDC and is sold under a 20-year gas agreement until July 2024 (“Gas Agreement”) to Songas Limited (“Songas”). Songas is the owner of the infrastructure that enables the gas to be delivered to Dar es Salaam, which includes a gas processing plant on Songo Songo Island. The Company operates the gas processing plant and field on a ‘no gain no loss’ basis and receives no revenue for the Protected Gas delivered to Songas.

Under the PSA, the Company has the right to produce and market all gas in the Songo Songo Block in excess of the Protected Gas requirements (“Additional Gas”).

The Tanzania Electricity Supply Company Limited (“TANESCO”) is a parastatal organization which is wholly-owned by the Government of Tanzania, with oversight by the Ministry for Energy (“ME”), previously known as the Ministry of Energy and Minerals (“MEM”). TANESCO is responsible for the generation, transmission and distribution of electricity throughout Tanzania. The Company currently supplies gas directly to TANESCO by way of a Portfolio Gas Supply Agreement (“PGSA”) and indirectly through the supply of Protected Gas and Additional Gas to Songas which in turn generates and sells power to TANESCO. TANESCO is the Company’s largest customer.

In addition to gas supplied to Songas and TANESCO for the generation of power, the Company has developed and supplies an industrial gas market in the Dar es Salaam area.

2 BASIS OF PREPARATION

These consolidated financial statements have been prepared on a historical cost basis and have been prepared using the accrual basis of accounting. The consolidated financial statements are presented in US dollars ("US$").

Statement of Compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). Certain comparative period amounts have been reclassified to conform with the current period presentation.

Basis of consolidation

Subsidiaries

Subsidiaries are those enterprises controlled by the Company. The following companies have been consolidated within the Orca Exploration financial statements:

Subsidiary	Registered	Holding	Functional currency
Orca Exploration Group Inc.	British Virgin Islands	Parent Company	US dollar
Orca Exploration Italy Inc.	British Virgin Islands	100%	Euro
Orca Exploration Italy Onshore Inc.	British Virgin Islands	100%	Euro
PAE PanAfrican Energy Corporation ("PAEM")	Mauritius	100%	US dollar
PanAfrican Energy Tanzania Limited	Jersey	100%	US dollar
Orca Exploration UK Services Limited	United Kingdom	100%	British Pound

Transactions eliminated upon consolidation

Inter-company balances and transactions and any unrealized gains or losses arising from inter-company transactions are eliminated in preparing the consolidated financial statements.

Foreign currency

i) Foreign currency transactions

Transactions in foreign currencies are recorded at the rate of exchange prevailing at the date of the transaction. Monetary assets and liabilities in foreign currencies are translated at period-end rates. Non-monetary items are translated at historic rates, unless such items are carried at market value, in which case they are translated using the exchange rates that existed when the values were determined. Any resulting exchange rate differences are recognized in earnings.

ii) Foreign currency translation

Foreign currency differences are recognized in comprehensive income and accumulated in the translation reserve. The assets and liabilities of these companies are translated into the functional currency at the period-end exchange rate. The income and expenses of the companies are translated into the functional currency at the average exchange rate for the period. Translation gains and losses are included in other comprehensive income.

3 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements.

Exploration and evaluation assets, property plant and equipment

i) Exploration and evaluation assets

Exploration and evaluation costs are capitalized as intangible assets. Intangible assets include lease and licence acquisition costs, geological and geophysical costs and other direct costs of exploration and evaluation which management considers to be unevaluated until reserves are appraised to be commercially viable and technologically feasible as commercial, at which time they are transferred to property, plant and equipment following an impairment review and depleted accordingly. Where properties are appraised to have no commercial value or are appraised at values less than book values, the associated costs are treated as an impairment loss in the period in which the determination is made.

ii) Property, plant and equipment

Property, plant and equipment comprises the Company's tangible natural gas assets, development wells, leasehold improvements, computer equipment, motor vehicles and fixtures and fittings carried at cost, less any accumulated depletion, depreciation and accumulated impairment losses. Cost includes purchase price and construction costs for qualifying assets. Depletion of these assets commences when the assets are ready for their intended use. Only costs that are directly related to the discovery and development of specific oil and gas reserves are capitalized. The cost associated with tangible natural gas assets are amortized on a field by field unit of production method based on commercial proven reserves. The calculation of the unit of production amortization takes into account the estimated future development cost associated with proven reserves.

iii) Impairment of exploration and evaluation assets, property, plant and equipment

At each balance sheet date, the Company reviews the carrying amounts of its property, plant and equipment and intangible assets to determine if indicators of impairment exist. Individual assets are grouped together as a cash generating unit ("CGU") for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are independent from other group assets. In the case of exploration and evaluation assets, this will normally be at the CGU level. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount. The recoverable amount is the higher of fair value less costs to sell and value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. In assessing the value in use, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value with a pre-tax discount rate that reflects the current market indicators. The fair value less costs to sell is the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. Where an impairment loss subsequently reverses, the carrying amount of the asset CGU is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the CGU in prior years. A reversal of an impairment loss is recognized in earnings.

Operatorship

The Company operates the Songo Songo gas field, flow lines and gas processing plant. The Songas wells, flowlines and gas plant are operated by the Company on behalf of Songas on a 'no gain no loss' basis. The cost of operating and maintaining the wells and flow lines is paid for by the Company and Songas in proportion to the respective volumes of Protected Gas and Additional Gas sales. The costs of operating and maintaining the wells and flow lines are reflected in the accounts to the extent that the costs were incurred to accomplish Additional Gas sales. The cost of operating the gas processing plant and pipeline to Dar es Salaam is paid by Songas. Costs incurred by the Company in connection with the operatorship of the Songas plant are recorded as receivables, which are re-charged to Songas. Subsequent payments received from Songas are credited to receivables. When there are Additional Gas sales, a tariff is paid to Songas as compensation for using the gas processing plant and pipeline. This tariff is netted against revenue as processing and transportation costs.

Employment benefits

i) Pension

The Company does not operate a pension plan, but it does make defined contributions to the statutory pension fund for employees in Tanzania. Obligations for contributions to the statutory pension fund are recognized as an expense in the income statement as incurred.

ii) Stock options

The stock option plan provides for the granting of stock options to directors, Company officers, key personnel and employees to acquire shares at an exercise price determined by the market value at the date of grant. The exercise price of each stock option is determined at the closing market price of the Class B shares on the day prior to the day of grant. Each stock option granted permits the holder to purchase one Class B share at the stated exercise price. The Company records a charge to earnings over the vesting period using the Black-Scholes fair valuation option pricing model. The valuation is dependent on a number of estimates, including the risk free interest rate, the level of stock volatility, and the estimate of the level of forfeiture.

iii) Stock appreciation rights and restricted stock units

Stock appreciation rights ("SARs") and restricted stock units ("RSUs") are issued to certain key managers, officers, directors and employees. The fair value of SARs and RSUs is expensed in the statement of comprehensive income in accordance with the service period. The fair value of the SARs and RSUs is revalued every reporting date with the change in the value recognized in earnings.

Asset retirement obligations

No provision has been made for future site restoration costs in Tanzania because the Company currently has no legal or contractual or constructive obligation under the PSA to restore the fields at the end of their commercial lives, should such occur within the term of the PSA. At such a time as the Company may be granted an extension of the term of the PSA, which encompasses the end of the field life, or other amendment to the PSA, which requires the Company to do so, a provision will be made for future site restoration costs.

Notes to the Consolidated Financial Statements

Revenue recognition, production sharing agreements and royalties

Pursuant to the terms of the PSA, the Company has exclusive rights to (i) to carry on Exploration Operations in the Songo Songo Gas Field; (ii) to carry on Development Operations in the Songo Songo Gas Field and (iii) jointly with TPDC, to sell or otherwise dispose of Additional Gas.

The Company recognizes revenue related to Additional Gas sales from the sale of gas to all customers, including both TANESCO and Songas, when title passes to the customer at fiscal gas meters which are installed at the respective customer's plant gate in Dar es Salaam. Under the terms of the PSA, the Company pays both its share and TPDC's share of operating, administrative and capital costs. The Company recovers all reasonably incurred operating, administrative and capital costs including TPDC's share of these costs from future revenues over several years ("Cost Gas"). TPDC's share of operating and administrative costs, are recorded in operating and general and administrative costs when incurred and capital costs are recorded in 'property, plant and equipment'. All recoveries are recorded as Cost Gas in the year of recovery.

The Company has a gas sales contract under which the customer is required to take, or pay for, a minimum quantity of gas. In the event that the customer has paid for gas that was not delivered, the additional income received by the Company is carried on the balance sheet as "deferred income". If the customer consumes volumes in excess of the minimum, it will be charged at the current rate, but may receive a credit for volumes paid but not delivered. At the end of each reporting period the Company reassesses the volumes for which the customer may receive credit, any remaining balance is credited to income.

In any given year, the Company is entitled to recover as Cost Gas up to 75% of the net revenue (gross revenue less processing and pipeline tariffs). Any net revenue in excess of the Cost Gas ("Profit Gas") is shared between the Company and TPDC in accordance with the terms of the PSA. Under the PSA the Company's share of Profit Gas is further increased by the amount necessary to fully pay and discharge any liability for taxes on income. Revenue represents the Company's share of Profit Gas and Cost Gas during the period.

Prior to 2016 the Company had reached an understanding with TANESCO that it would continue to supply gas if TANESCO remained reasonably current with payments for gas deliveries. As a result of TANESCO's inability to fully pay amounts invoiced by the Company for the past few years, management of the Company has modified its approach to revenue recognition as it relates to TANESCO only. Commencing on October 1, 2016 the Company began recording revenues for sales to TANESCO based on the expected amount to be collected, which represents a percentage of the amounts invoiced to TANESCO determined by comparison of TANESCO's payment history to the amounts invoiced by the Company. Management believes this approach provides the best estimate of TANESCO's ability to pay and remain reasonably current, and as well, reflects the economic reality of the situation (see Notes 4 and 7).

For cash received in excess of the revenue recorded from TANESCO in any given period, the additional amounts received will be recorded as deferred revenue. In periods when the deferred revenue balance is greater than the average amounts invoiced to TANESCO for gas deliveries in the previous four quarters, any amount in excess of the four quarter average will be recorded as current period revenue to the extent there is unrecognized revenue resulting from the approach to revenue recognition adopted on October 1, 2016. If such unrecognized revenue is reduced to nil, additional amounts collected in excess of the quarterly average will be applied against the oldest TANESCO invoice recorded and previously provided for (see Note 12).

In periods when cash received is less than revenue recorded, the deferred revenue will be reduced accordingly. If the deferred revenue amount is reduced to nil, the difference will be recorded as accounts receivable.

The percentage used to recognize TANESCO revenue will be reviewed as circumstances require. If there is a significant difference between the amount of revenue recorded and amounts received, the percentage used to record revenue as well as any existing receivable or deferred revenue balance will be revised accordingly. The percentage was increased effective October 1, 2017 to reflect the most recent three year payment history for TANESCO compared to amounts invoiced for deliveries.

Additional Profits Tax

Under the terms of the PSA, in the event that all costs have been recovered with an annual return from the PSA of 25% plus the percentage change in the United States Industrial Goods Producer Price Index, an Additional Profits Tax ("APT") is payable to the Government of Tanzania. APT is provided for by forecasting the total APT payable in the future as a proportion of the forecast Profit Gas over the term of PSA licence. The actual APT that will be paid is dependent on the achieved value of the Additional Gas sales and the quantum and timing of the operating costs and capital expenditure program.

The PSA states that APT shall be calculated for each year and shall vary with the real rate of return earned by the Company on the net cash flow from the Contract Area (as defined). The calculation of APT includes a working capital adjustment reflecting the effect of the timing of actual receipt of amounts owing from TANESCO on net cash flow available to APT.

Income taxes

The Company is liable for Tanzanian income tax on the income for the year; this comprises current and deferred tax. Where current income tax is payable, this is shown as a current tax liability. Deferred tax is provided using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. The amount of deferred tax provided is based on the expected manner of realization or settlement of carrying amounts of assets and liabilities using tax rates substantively enacted at the balance sheet date. A deferred tax asset is recognized only to the extent that it is probable that future taxable profits will be available, against which the asset can be utilized. Deferred tax assets are reduced to the extent that it is no longer probable that the related tax benefits will be realized.

Depreciation

Depreciation for non-natural gas properties is charged to earnings on a straight line basis over the estimated useful economic lives of each class of asset. The estimated useful lives are as follows:

Leasehold improvement	Over remaining life of the lease
Computer equipment	3 years
Vehicles	3 years
Fixtures and fittings	3 years

Financial instruments

All financial instruments are initially recognized at fair value on the consolidated statement of financial position. The Company has classified each financial instrument into one of the following categories: (i) fair value through the statement of comprehensive income (loss), (ii) loans and receivables, and (iii) other financial liabilities. Subsequent measurement of financial instruments is based on their classification.

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership. Financial assets and liabilities are offset and the net amount is reported on the statement of financial position when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Notes to the Consolidated Financial Statements

Initial recognition

At initial recognition, the Company classifies its financial instruments in the following categories depending on the purpose for which the instruments were acquired:

i) **Financial assets and liabilities at fair value through statement of comprehensive loss:**

A financial asset or liability classified in this category is recognized at each period at fair value with gains and losses from revaluation being recognized in net income. A financial asset or liability is classified in this category if acquired principally for the purpose of selling or repurchasing in the short-term. Derivatives are also included in this category unless they are designated as hedges.

ii) **Loans and receivables:**

Loans and receivables are initially measured at fair value plus directly attributable transaction costs and are subsequently recorded at amortized cost using the effective interest method.

Long-term receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Long-term receivables are initially recognized at fair value based on the discounted cash flows. The discount rate is based on the credit quality and term of the financial instrument. The financial instrument is subsequently valued at amortized costs by accreting the instrument over the expected life of the assets. The accretion associated with instrument valued at amortized cost is reported on the statement of comprehensive loss each reporting period.

The fair value of the Company's trade and other receivables approximates their carrying values due to the short-term nature of these instruments.

iii) **Other financial liabilities:**

Trade and other payables and the long-term loan are classified as other financial liabilities and are initially measured at fair value less directly attributable transaction costs and are subsequently recorded at amortized cost using the effective interest method. The fair value of trade and other payables approximates the carrying amounts due to the short-term nature of these instruments. The fair value of the long-term loan approximates its carrying value as there has been no significant change in interest rates since the Company finalized the loan. The loan interest rate is fixed at 10%.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, term deposits and short-term highly liquid investments with the original term to maturity of three months or less, which are convertible to known amounts of cash and which, in the opinion of management, are subject to an insignificant risk of changes in value. The fair value of cash and cash equivalents approximates their carrying amount. There are no restrictions on the movement of funds out of Tanzania.

Impairment of financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in earnings. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in earnings.

Future accounting changes

The following pronouncements from the IASB will become effective or were amended for financial reporting periods beginning on or after January 1, 2018 and have not yet been adopted by the Company. These new or revised standards permit early adoption with transitional arrangements depending upon the date of initial application.

IFRS 9 – Financial Instruments replaces the existing guidance in IAS 39 Financial Instruments: Recognition and Measurement. The new standard includes revised guidance on the classification and measurement of financial instruments, including a new expected credit loss model for calculating impairment on financial assets, and the new general hedge accounting requirements. It also carries forward the guidance on recognition and de-recognition of financial instruments from IAS 39. IFRS 9 is effective for annual reporting periods beginning on or after January 1, 2018 with early adoption permitted. The Company currently does not apply hedge accounting to its financial instruments and does not currently intend to apply hedge accounting to any of its financial instruments upon adoption of IFRS 9.

IFRS 15 – Revenue from Contracts with Customers establishes a comprehensive framework for determining whether, how much and when revenue is recognized. It replaces existing revenue recognition guidance, including IAS 18 Revenue, IAS 11 Construction Contracts and IFRIC 13 Customer Loyalty Programs. IFRS 15 is effective for annual reporting periods beginning on or after January 1, 2018 with early adoption permitted. The Company will adopt IFRS 15 using the modified retrospective approach on January 1, 2018. Based on the Company's review of contracts with customers and its assessment of various revenue streams, at this time, the Company is not able to assess the impact that the adoption of IFRS 15 will have on the Company's net income (loss) and financial position. However, the Company is still in the process of reviewing all of its contracts and fully assessing the financial statement impact. The Company does anticipate expanding disclosures in the notes to its consolidated financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue streams by product type.

IFRS 16 – Leases sets out the principles for the recognition, measurement, presentation and disclosure of leases for both parties to a contract, i.e. the customer ('lessee') and the supplier ('lessor') and replaces the previous leases standard, IAS 17 Leases. IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019. The Company is in the early stages of evaluating the impact of IFRS 16 on its consolidated financial statements and the extent of the impact has not yet been determined.

4 USE OF ESTIMATES AND JUDGEMENTS

The following are the critical judgements, apart from those involving estimations (see below), that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the accounts recognized in these consolidated financial statements.

Critical judgements in applying accounting policies:

A. Property, plant and equipment

The Company assesses its property, plant and equipment for impairment when events or circumstances indicate that the carrying amount of its assets may not be recoverable. If any indication of impairment exists, the Company performs an impairment test on the CGU, which is the lowest level at which there are identifiable cash flows. The carrying amount of the CGU is compared to its recoverable amount which is defined as the greater of its fair value less cost to sell and value in use and is subject to management estimates. These estimates include quantities of reserves and future production, future commodity pricing, development costs, operating costs, and discount rates. Any changes in these estimates may have an impact on the recoverable amount of the CGU.

Property, plant and equipment is measured at cost less accumulated depreciation, depletion and amortization. The Company's oil and natural gas properties are depleted using the unit-of-production method over proved reserves. The unit-of-production method takes into account estimates of capital expenditures incurred to date along with future development capital required to develop the proved reserves.

B. Collectability of receivables

The Company evaluates the collectability of its receivables on the basis of payment history, frequency and predictability, as well as Management's assessment of the customer's willingness and ability to pay. Management performs impairment tests each period on the Company's current and long-term receivables.

Prior to 2016 the Company had reached an understanding with TANESCO that it would continue to supply gas if TANESCO remained reasonably current with payments for gas deliveries. Up to September 30, 2016 the Company recorded revenue from TANESCO based on volumes delivered, however, TANESCO payments were inconsistent and not always in compliance with the agreed understanding resulting in the Company recording provisions for doubtful accounts for amounts outstanding from TANESCO for more than 60 days. Commencing on October 1, 2016 the Company began recording revenues for sales to TANESCO based on the expected amount to be collected, which represents a percentage of the amounts invoiced to TANESCO determined by comparison of TANESCO's payment history to the amounts invoiced by the Company over the previous three years. Management believes this approach provides the best estimate of TANESCO's ability to pay and remain reasonably current, and as well, reflects the economic reality of the situation (see Notes 7 and 12).

C. Statutory taxes

The Company operates in a jurisdiction with complex tax laws and regulations, which are evolving over time. The Company has taken certain tax positions in its tax filings and these filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax impact may differ significantly from that estimated and recorded by management.

Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period in which the change occurs.

Key sources of estimation of uncertainty

D. **Reserves and APT**

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and cash flows to be derived therefrom, including many factors beyond the control of the Company. The reserve and cash flow information contained herein represents estimates only and are used to estimate APT by forecasting the total APT payable in the future as a proportion of the forecast Profit Gas over the term of PSA licence. The actual APT to be paid is dependent on the achieved value of the Additional Gas sales and the quantum and timing of the operating costs and capital expenditure program.

The reserves and estimated future net cash flow from the Company's properties have been evaluated by independent petroleum engineers. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, crude oil price differentials to benchmarks, future prices of oil and natural gas, operating costs, transportation costs, cost recovery provisions and royalties, TPDC "back-in" methodology and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date of the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. For the purpose of the reserves certification as at December 31, 2017 it was assumed that TPDC will elect to 'back-in' for 20% for all future new drilling activities after well SS-12 and this is reflected in the Company's net reserve position. As at the date of the consolidated financial statements, TPDC has made no such election.

Reserves are integral to the amount of depletion and impairment test.

E. **Fair value of stock based compensation**

All stock options issued or stock appreciation rights granted by the Company are required to be valued at their fair value. In assessing the fair value of the equity based compensation, estimates have to be made as to (i) the volatility in share price, (ii) the risk free rate of interest, and (iii) the level of forfeiture. In the case of stock options, this fair value is estimated at the date of issue and is not revalued, whereas the fair value of stock appreciation rights is recalculated at each reporting period.

F. **Cost recovery**

The Company is able to recover reasonable costs incurred on the development of the Songo Songo project out of 75% of the gross field revenue less processing and pipeline tariffs ("field net revenue"). There are inherent uncertainties in estimating when costs have been recovered as these costs are subject to government audit and in exceptional circumstances a potential reassessment after the elapse of a considerable period of time.

G. **Financial instrument classification and measurement**

The Company classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including expected interest rate, share prices, and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuation in this level are those with inputs for the asset or liabilities that are not based on observable market data.

Notes to the Consolidated Financial Statements

5 RISK MANAGEMENT

The Company, by its activities in oil and gas exploration, development and production, is exposed to the risk associated with the unpredictable nature of the financial markets as well as political risk associated with conducting operations in an emerging market. The Company seeks to manage its exposure to these risks wherever possible.

A. Foreign exchange risk

Foreign exchange risk arises when transactions and recognized assets and liabilities of the Company are denominated in a currency that is not the US dollar functional currency.

The Company operates internationally and is exposed to foreign exchange risk arising from currency exposures to US dollars. The main currencies to which the Company has an exposure are: Tanzanian shillings, British pounds sterling, Euros and Canadian dollars.

The majority of the expenditure associated with the operation of the gas distribution system is denominated in Tanzanian shillings. Whilst conversion of Tanzanian shillings into US dollars is unrestricted, the foreign exchange market for Tanzanian shillings is limited and not highly liquid, reducing the Company's ability to convert large amounts of Tanzanian shillings into US dollars at any given time. To mitigate the risk of Tanzanian shilling devaluation, the Company regularly converts Tanzanian shilling receipts into US dollars to the extent practicable. Capital stock, equity financing and any associated stock based compensation are denominated in Canadian dollars. The operational revenue and the majority of capital expenditures are denominated in US dollars.

There are no forward exchange rate contracts in place.

A 10% increase in the US dollar against the relevant foreign currency would result in an overall increase in working capital (defined as current assets less current liabilities) of US$0.4 million to US$70.0 million and an increase in the income before tax to US$6.7 million. The sensitivity includes only outstanding foreign currency denominated monetary items and adjusts their translation at period end for a 10% change in the foreign currency rates. A 10% sensitivity rate is used when reporting foreign currency risk internally to key management personnel and represents management's assessment of the reasonable possible change in foreign exchange rates.

The following balances are denominated in foreign currency (stated in US dollars at period end exchange rates:

Balances as at December 31, 2017

US$'millions	Canadian dollars	Tanzanian shillings	Euros	Other currencies	Total
Cash	1.2	5.0	1.9	1.2	9.3
Trade and other receivables	–	3.0	0.5	1.3	4.8
Trade and other payables	(7.9)	(1.6)	(0.5)	(0.1)	(10.1)
	(6.7)	6.4	1.9	2.4	4.0

B. Commodity price risk

The Company negotiated industrial gas sales contracts with gas prices which, subject to certain floors and ceilings, are determined as a discount to the lowest cost alternative fuels in Dar es Salaam, namely Heavy Fuel Oil ("HFO") and coal. The price of HFO is exposed to the volatility in the market price of crude oil.

C. Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company has minimal exposure to interest rates as the long-term loan has a fixed interest rate and interest received on cash balances is not significant.

D. Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from TANESCO and Songas. The carrying amount of accounts receivable and the long-term receivable represents the maximum credit exposure. As at December 31, 2017 and 2016, provisions exist against the long-term TANESCO receivable, the provision for gas plant operations charges and capital expenditure receivables from Songas and the provision of US$0.5 million for one industrial customer. No write-off any receivables occurred in 2017 or 2016 (see Note 12).

All the Company's production is currently derived in Tanzania. The sales are made to the Power sector and the Industrial sector. In relation to sales to the Power sector, the Company has a contract with Songas for the supply of gas to the Ubungo power plant and a contract with TANESCO to supply gas to some of the TANESCO power plants. The contracts with Songas and TANESCO accounted for 48% of the Company's gross field revenue operating revenue during 2017 and US$2.4 million of the short and long-term receivables at year-end.

Sales to the Industrial sector are subject to an internal credit review to minimize the risk of non-payment.

The Company manages the credit exposure related to cash and cash equivalents by selecting counterparties based on credit ratings and monitoring all investments to ensure a stable return, avoiding complex investment vehicles with higher risk such as asset backed commercial paper. The Company's cash resources are placed with reputable financial institutions with no history of default.

E. Liquidity risk

Liquidity risk is the risk that the Company will not have sufficient funds to meet its liabilities. Cash forecasts identifying liquidity requirements of the Company are produced on a regular basis. These are reviewed to ensure sufficient funds exist to finance the Company's current operational and investment cash flow requirements. The Company has US$56.8 million of financial liabilities with regards to trade and other payables of which US$33.4 million is due within one to three months, nil is due within three to six months, and US$23.4 million is due within six to twelve months (see Note 14). As at year-end the Company had a current tax liability of US$0.7 million.

At the end of the year approximately 61% of the current liabilities relate to TPDC (see Note 14). The amounts due to TPDC represent its share of Profit Gas; in accordance with the terms of the PSA, TPDC is entitled to the payment of its share of Profit Gas on a quarterly basis proportional to the cash receipts during the quarter. A large proportion of the TPDC liability is associated with the long-term TANESCO arrears and payment to TPDC will be made once cash is received for the arrears. Prior to 2017 payments from TANESCO have been irregular and insufficient and as a result, the quarterly payments to TPDC have been disrupted.

F. Capital risk management

The Company's objectives when managing capital are to safeguard the Company's ability to continue as a going concern in order to provide returns for shareholders and benefits for other stakeholders and to achieve an optimal capital structure to reduce the cost of capital. The level of risk currently in Tanzania prohibits the optimization of capital structure as many sources of traditional capital are unavailable.

G. Country risk

The Company has unresolved disputes with TPDC related Cost Gas revenue, with TANESCO and SONGAS regarding unpaid invoices and the Tanzanian Revenue Authority ("TRA") on tax disputes. The Company continues to rely upon its rights under the existing PSA and has initiated notices of disputes as required under the PSA and by local tax regulations to resolve outstanding issues. The Company has put in place an advisory committee of experienced individuals with significant experience working with the Tanzanian government to mitigate the risks of doing business in Tanzania.

Notes to the Consolidated Financial Statements

6
SEGMENT INFORMATION

The Company has one reportable industry segment which is international exploration, development and production of petroleum and natural gas. The Company currently has producing and exploration assets in Tanzania and had exploration and appraisal interests in Italy.

	2017			2016		
US$'000	**Italy**	**Tanzania**	**Total**	**Italy**	**Tanzania**	**Total**
External revenue	**–**	**51,854**	**51,854**	–	65,885	65,885
Segment income (loss) [(1)]	**173**	**(2,673)**	**(2,500)**	(100)	2,264	2,164
Non-cash charge [(2)]	**–**	**2,956**	**2,956**	–	14,245	14,245
Depletion & depreciation	**–**	**9,027**	**9,027**	–	9,777	9,777
Capital expenditures [(3)]	**–**	**8,897**	**8,897**	–	16,924	16,924
Total assets	**2,041**	**247,508**	**249,549**	1,477	219,653	221,130
Total liabilities	**493**	**170,325**	**170,818**	102	141,005	141,107

(1) The income in Italy relates to foreign exchange gains on the euro cash balances held in country.

(2) Other non-cash charges for 2017 includes VAT and for 2016, it includes VAT and amounts provided for doubtful accounts receivable from TANESCO recorded directly to earnings.

(3) See Notes 12 & 13.

7 REVENUE

US$'000	YEARS ENDED DECEMBER 31 2017	2016
Industrial sector	**35,440**	35,626
Power sector	**35,916**	39,751
Gross field revenue	**71,356**	75,377
Processing and transportation tariff	**(8,978)**	(10,057)
Net field revenue	**62,378**	65,320
TPDC share of revenue	**(17,640)**	(9,798)
Company operating revenue	**44,738**	55,522
Current income tax adjustment	**7,116**	10,363
Revenue	**51,854**	65,885

The Company records a percentage of the amounts invoiced to TANESCO for revenue recognition purposes determined by comparison of TANESCO's payment history to the amounts invoiced by the Company.

As a result of recording revenue based on the expected collectability from the effective date, there is the following impact:

US$'000	AS AT DECEMBER 31 2017	2016
Decrease in net field revenue and accounts receivable	**2,247**	1,925
Increase (decrease) in revenue	**83**	(1,636)
Increase (decrease) in net income	**347**	(1,599)
Decrease in liabilities	**2,594**	326

The reduction of TANESCO revenue based on the collectability approach has the impact of reducing the net field revenue that is available for allocation between PAET and TPDC in accordance with the terms of the PSA. During the year, the reduction of net field revenue has had an impact on the timing of Cost Gas recovery resulting in PAET's share of net field revenue increasing by US$0.1 million and TPDC share being reduced by US$2.3 million. Since the start of recording revenue on an expected collectability basis, the cumulative impact has been a US$4.2 million reduction in net field revenue which has been allocated 63% to TPDC and 37% to PAET following the recovery of the Cost Pool in 2017. During 2016, 85% of the reduction in net field revenue was allocated to PAET and 15% to TPDC.

8 PERSONNEL EXPENSES

Personnel costs are as follows:

	YEARS ENDED DECEMBER 31	
US$'000	**2017**	2016
Wages and salaries	**9,540**	10,589
Social security costs	**343**	629
Other statutory costs	**330**	284
	10,213	11,502
Stock based compensation	**6,619**	2,591
	16,832	14,093

Stock based compensation is recorded within general and administrative expenses in the statement of comprehensive (loss) income. The balance of personnel expenses for 2017 of US$10.2 million (2016: US$11.5 million) is recorded in distribution and production expenses and general administrative expenses at US$2.0 million (2016: US$2.6 million) and US$8.2 million (2016: US$8.9 million), respectively. Personnel expenses include Company employees who operate the plant on behalf of Songas; these expenses are recharged to Songas.

9 FINANCE EXPENSE

US$'000	YEARS ENDED DECEMBER 31 **2017**	2016
Interest expense	**(6,250)**	(5,668)
Participatory interest expense	**(3,809)**	–
Net foreign exchange gain (loss)	**184**	(24)
Provision for doubtful accounts	**90**	(12,853)
Indirect tax	**(3,046)**	(1,392)
Finance expense	**(12,831)**	(19,937)

Interest expense and participatory interest expense relate to the long-term loan with the International Finance Corporation ("IFC"). The amount of interest expense during the year was US$6.3 million (2016: US$5.7 million); the interest expense is payable quarterly in arrears. The participatory interest expense of US$3.8 million (2016: US$ nil) is paid annually in arrears, it equates to 7% of PAET's net cash flows from operating activities net of net cash flows used in investing activities for the year (see Note 15).

The indirect tax of US$3.0 million for the year (2016: US$1.4 million) is for VAT associated with invoices to TANESCO for interest on late payments and invoices under the provisions within the PGSA for differences between gas contracted for delivery and gas taken by TANESCO. These invoices are not recognized in the financial statements due to revenue recognition criteria with respect to assurance of collectability (see Note 12).

The provision for doubtful accounts for the year ended December 31, 2017 of US$0.1 million represents a receipt from an industrial debtor which had been previously provided against. The provision for doubtful accounts for the year ended December 31, 2016 includes US$12.4 million for overdue TANESCO receivables and US$0.4 million relates to Industrial customers. Prior to October 1, 2016 any TANESCO receivable which was older than 60 days was provided for and a provision for doubtful accounts was recognized in the financial statements.

Notes to the Consolidated Financial Statements

10 INCOME TAXES

The tax charge is as follows:

	YEARS ENDED DECEMBER 31	
US$'000	**2017**	2016
Current tax	**7,873**	9,719
Deferred tax (recovery) expense	**(1,162)**	3,661
	6,711	13,380

Tax of US$1.4 million was paid during the year in relation to the settlement of the prior year's tax liability (2016: US$1.2 million). In addition, installment tax payments totaling US$8.7 million were made in respect of the current year (2016: US$8.3 million). These are presented as a reduction in tax payable on the statement of financial position.

Tax rate reconciliation

	YEARS ENDED DECEMBER 31	
US$'000	**2017**	2016
Income before tax per Consolidated Statements of Comprehensive (Loss) Income	**6,274**	16,770
Less Additional Profits Tax	**(2,063)**	(1,226)
Income before statutory tax	**4,211**	15,554
Provision for income tax calculated at the statutory rate of 30%	**1,263**	4,663
Effect on income tax of:		
Administrative and operating expenses	**1,732**	1,343
Foreign exchange (gain) loss	**(47)**	48
Stock-based compensation	**1,596**	777
TANESCO interest not recognized as interest income (Note 9)	**1,661**	1,062
Unrecognized tax asset	**468**	5,445
Other permanent differences	**38**	42
	6,711	13,380

As at December 31, 2017, the provision for doubtful debt from TANESCO has resulted in a US$23.9 million unrecognized deferred tax asset (2016: US$23.1 million). If this amount was ultimately not recovered, the Company would also be entitled to a US$17.8 million recovery of Value Added Tax.

A deferred tax asset of US$2.2 million in respect of Longastrino Italy exploration and evaluation costs has not been recognized because it is not probable that there will be future profits against which this can be utilized (2016: US$2.2 million).

The deferred income tax liability includes the following temporary differences:

	AS AT DECEMBER 31	
US$'000	**2017**	2016
Differences between tax base and carrying value of property, plant and equipment	**(22,444)**	(21,563)
Tax recoverable from TPDC	**(3,378)**	(4,142)
Provision for doubtful debt	**3,080**	3,110
Additional Profits Tax	**10,381**	9,787
Unrealized exchange losses/other provisions	**550**	(165)
	(11,811)	(12,973)

11 ADDITIONAL PROFITS TAX

Under the terms of the PSA, in the event that all costs have been recovered with an annual cash return from the PSA of 25% plus the percentage change in the United States Industrial Goods Producer Price Index ("PPI"), an Additional Profits Tax ("APT") is payable.

The Company provides for APT by forecasting the total APT payable as a proportion of the forecast Profit Gas over the term of the PSA. The effective APT rate of 19.4% (2016: 18.8%) has been applied to Profit Gas of US$10.6 million (2016: US$6.5 million). Accordingly, US$2.1 million of APT has been recorded as an other income tax for the year ended December 31, 2017 (2016: US$1.2 million).

Notes to the Consolidated Financial Statements

12 TRADE AND OTHER RECEIVABLES

Current receivables

US$'000	AS AT DECEMBER 31 **2017**	2016
Trade receivables		
TANESCO	**–**	5,749
Songas	**2,378**	2,218
Industrial customers	**6,915**	7,463
Less provision for doubtful accounts	**(452)**	(550)
	8,841	14,880
Other receivables		
Songas gas plant operations	**5,827**	6,601
Songas well workover programme	**–**	14,458
Other	**2,521**	1,516
Less provision for doubtful accounts	**(4,916)**	(9,817)
	3,432	12,758
	12,273	27,638

Trade receivables aged analysis

	AS AT DECEMBER 31, 2017				
US$'000	Current	>30 <60	>60 <90	>90	Total
Songas	1,210	1,168	–	–	**2,378**
Industrial customers	3,718	2,155	402	640	**6,915**
Less provision for doubtful accounts	–	–	–	(452)	**(452)**
	4,928	3,323	402	188	**8,841**

	AS AT DECEMBER 31, 2016				
US$'000	Current	>30 <60	>60 <90	>90	Total
TANESCO	2,570	2,559	620	–	5,749
Songas	1,190	1,028	–	–	2,218
Industrial customers	2,769	3,679	235	780	7,463
Less provision for doubtful accounts	–	–	–	(550)	(550)
	6,529	7,266	855	230	14,880

TANESCO

At December 31, 2017 the current receivable from TANESCO was US$ nil (December 31, 2016: US$5.7 million). During the year, the amounts received from TANESCO were in excess of the revenue recognized for gas sales to TANESCO resulting in a deferred revenue balance of US$8.4 million (December 31, 2016: US$ nil), after the reallocation of US$3.8 million to net field revenue during 2017.

The TANESCO long-term trade receivable at December 31, 2017 and 2016 was US$74.4 million (provision of US$74.4 million). Subsequent to December 31, 2017 the Company has invoiced TANESCO US$6.2 million for 2018 gas deliveries and TANESCO has paid the Company US$10.0 million.

Long-term receivables

US$'000	AS AT DECEMBER 31 2017	2016
TANESCO receivable	**74,361**	74,361
Provision for doubtful accounts	**(74,361)**	(74,361)
Net TANESCO receivable	**–**	–
VAT Songas workovers	**2,205**	–
VAT bond	**363**	318
Lease deposit	**229**	207
Long-term receivables	**2,797**	525

Songas

As at December 31, 2017 Songas owed the Company US$8.2 million (2016: US$23.3 million), while the Company owed Songas US$2.0 million (December 31, 2016: US$2.3 million). The amounts due to the Company are mainly for sales of gas of US$2.4 million (2016: US$2.2 million) and for the operation of the gas plant of US$5.8 million (2016: US$6.6 million) against which the Company has made a provision for doubtful accounts of US$4.9 million (2016: US$9.8 million) whereas the amounts due to Songas primarily relate to pipeline tariff charges of US$1.7 million (2016: US$1.9 million). The operation of the gas plant is conducted at cost and the charges are billed to Songas on a flow through basis.

In Q1 2017, based on agreement with TPDC, the Songas share of workover costs of US$14.5 million were transferred to the cost pool to recover the costs via the PSA cost recovery mechanism. This resulted in:

i) US$7.4 million of the Songas receivable being reclassified to plant, property and equipment equal to the proportion not previously provided against. This represents the value which will be recovered via the PSA revenue sharing mechanism;

ii) the write-off of the US$4.9 million portion of the Songas receivable that had been previously provided for; and

iii) US$2.2 million relating to VAT on the workovers that had already been paid being reclassified as a long-term receivable. The Company continues to take action to collect the US$14.5 million of workover costs. Amounts not collected will be pursued through the mechanisms provided in the agreements with Songas.

All amounts due to and from Songas have been summarized in the table below:

	January 1, 2017	Year to date transactions	December 31, 2017	Post year-end payments and receipts	Outstanding as at the date of this report
Pipeline tariff – payable	(1,893)	223	**(1,670)**	1,670	–
Gas sales – receivable	2,218	160	**2,378**	(2,378)	–
Gas plant operation receivable	6,601	(774)	**5,827**	(359)	5,468
Provision for gas plant operation receivable	(4,916)	–	**(4,916)**	–	(4,916)
Workover program	14,458	(14,458)	**–**	–	–
Provision for workover program receivable	(4,901)	4,901	**–**	–	–
Other payable	(378)	–	**(378)**	–	(378)
Net balances	11,189	(9,948)	**1,241**	(1,067)	174

13 PROPERTY, PLANT AND EQUIPMENT

US$'000	Oil & natural gas interests	Leasehold improvements	Computer equipment	Vehicles	Fixtures & fittings	Total
Costs						
As at January 1, 2017	195,622	699	1,303	380	1,126	199,130
Additions [(1)]	8,644	–	184	69	–	8,897
As at December 31, 2017	**204,266**	**699**	**1,487**	**449**	**1,126**	**208,027**
Accumulated depletion and depreciation						
As at January 1, 2017	84,580	519	1,241	249	1,120	87,709
Depletion and depreciation	8,678	175	74	97	3	9,027
As at December 31, 2017	**93,258**	**694**	**1,315**	**346**	**1,123**	**96,736**
Net book values						
As at December 31, 2017	**111,008**	**5**	**172**	**103**	**3**	**111,291**

(1) Additions include a transfer of US$7.4 million in relation to the Songas share of workover costs (see Note 12).

US$'000	Oil & natural gas interests	Leasehold improvements	Computer equipment	Vehicles	Fixtures & fittings	Total
Costs						
As at January 1, 2016	178,806	699	1,278	297	1,126	182,206
Additions	16,816	–	25	83	–	16,924
As at December 31, 2016	195,622	699	1,303	380	1,126	199,130
Accumulated depletion and depreciation						
As at January 1, 2016	75,389	238	1,105	168	1,032	77,932
Depletion and depreciation	9,191	281	136	81	88	9,777
As at December 31, 2016	84,580	519	1,241	249	1,120	87,709
Net book values						
As at December 31, 2016	111,042	180	62	131	6	111,421

In determining the depletion charge, it is estimated that future development costs of US$80.4 million (2016: US$84.0 million) will be required to bring the total proved reserves to production. The decrease in estimated future development costs is a result of expenditures during the year of US$1.2 million and revision of future cost estimates. The future capital expenditures are estimates of costs required to ensure the Company can produce the required gas volumes to meet its contractual obligations for the remaining life of the licence. During the year the Company recorded depreciation of US$0.3 million (2016: US$0.6 million) in general and administrative expenses.

14 TRADE AND OTHER PAYABLES

US$'000	AS AT DECEMBER 31 2017	2016
Songas	**1,670**	1,893
Other trade payables	**1,961**	3,245
Trade payables	**3,631**	5,138
TPDC share of Profit Gas, net	**33,422**	22,917
Accrued liabilities	**19,705**	6,250
	56,758	34,305

TPDC share of Profit Gas

US$'000	AS AT DECEMBER 31 2017	2016
TPDC share of Profit Gas	**35,876**	28,319
Less "Adjustment Factor"	**(2,454)**	(5,402)
TPDC share of Profit Gas payable	**33,422**	22,917

Under the PSA revenue sharing mechanism, the Company is to adjust TPDC's Profit Gas share by the "Adjustment Factor". The Adjustment Factor is equal to the amount necessary to fully pay and discharge the PAET liability for taxes on income derived from Petroleum Operations. The Adjustment Factor has previously been carried as tax recoverable in the Consolidated Statements of Financial Position and has been reclassified to trade and other payables to reflect the right and practice of net settlement.

Notes to the Consolidated Financial Statements

15 LONG-TERM LOAN

The Company's subsidiary, PAET, entered into a loan agreement (the "Loan") in 2015 with the International Finance Corporation ("IFC"), a member of the World Bank Group, for US$60 million.

The term of the Loan is ten years, with no repayment of principal for the first seven years, followed by a three-year amortization period. The Loan is to be paid out through six semi-annual payments of US$5 million starting April 15, 2022 and one final payment of US$30 million due on April 15, 2025. The Company may voluntarily prepay all or part of the Loan but must simultaneously pay any accrued base interest costs related to the principal amount being prepaid. If any portion of the Loan is prepaid prior to the fourth anniversary of the first drawdown, the Company would be required to pay the accrued base interest as if the prepaid portion of the Loan had remained outstanding for the full four years. The Loan is an unsecured subordinated obligation of PAET and is guaranteed by the Company to a maximum of US$30 million. The guarantee may only be called upon by IFC at maturity in 2025 and, subject to IFC approval and receipt of all required regulatory approvals, the Company at its discretion may issue shares in fulfillment of all or part of the guarantee obligation in 2025.

Base interest on the Loan is payable quarterly at 10% per annum on a 'pay-if-you-can-basis' using a formula to calculate the net cash available for such payments as at any given interest payment date. To date, all interest incurred has been paid. In addition, an annual variable participatory interest equating to 7% of the net cash flow from operating activities less net cash flows used in investing activities of PAET in respect of any given year. Such participatory interest will continue until October 15, 2026 regardless whether the Loan is repaid prior to its contractual maturity date. For the year ended December 31, 2017 the participatory interest was US$3.8 million (2016: US$ nil) and is included in trade and other payables (see Note 14). Dividends and distributions from PAET to the Company are restricted at any time that any amounts of unpaid interest, principal or participating interest are outstanding.

	AS AT DECEMBER 31	
US$'000	**2017**	2016
Loan principal	**60,000**	60,000
Financing costs	**(1,482)**	(1,601)
	58,518	58,399

16 CAPITAL STOCK

Authorised

50,000,000	Class A common shares	No par value
100,000,000	Class B subordinate voting shares	No par value
100,000,000	First preference shares	No par value

The Class A and Class B shares rank pari passu in respect of dividends and repayment of capital in the event of winding-up. Class A shares carry twenty (20) votes per share and Class B shares carry one vote per share. The Class A shares are convertible at the option of the holder at any time into Class B shares on a one-for-one basis. The Class B shares are convertible into Class A shares on a one-for-one basis in the event that a take-over bid is made to purchase Class A shares which must, by reason of a stock exchange or legal requirements, be made to all or substantially all of the holders of Class A shares and which is not concurrently made to holders of Class B shares.

Changes in the capital stock of the Company were as follows:

	2017			2016		
Number of shares	**Authorised** *(000)*	**Issued** *(000)*	**Amount** *(US$'000)*	Authorised *(000)*	Issued *(000)*	Amount *(US$'000)*
Class A						
As at December 31	**50,000**	**1,751**	**983**	50,000	1,751	983
Class B						
As at January 1	**100,000**	**33,106**	**84,505**	100,000	33,106	84,505
Stock options	**–**	**400**	**1,020**	–	–	–
As at December 31	**100,000**	**33,506**	**85,525**	100,000	33,106	84,505
First preference						
As at December 31	**100,000**	**–**	**–**	100,000	–	–
Total Class A, Class B and first preference	**250,000**	**35,257**	**86,508**	250,000	34,857	85,488

All issued capital stock is fully paid.

	2017		2016	
Stock Options	**Options** *(000)*	**Exercise price** *CDN$*	**Options** *(000)*	**Exercise price** *CDN$*
Outstanding as at January 1	**–**	**–**	–	–
Issued	**400**	**3.18**		
Exercised	**(400)**	**3.18**	–	–
Outstanding as at December 31	**–**	**–**	–	–

Stock Appreciation Rights ("SARs")	2017 SARs (000)	2017 Exercise price (CDN$)	2016 SARs (000)	2016 Exercise price (CDN$)
Outstanding as at January 1	2,430	2.12 to 3.25	3,100	2.12 to 3.25
Exercised	(160)	2.12 to 2.30	(260)	2.12 to 2.30
Exercised	(165)	2.32 to 2.70	(265)	2.32 to 2.70
Exercised	(25)	3.02 to 3.25	(55)	3.02 to 3.25
Granted	90	2.12.to 2.30	–	–
Granted	365	3.84 to 3.87	–	–
Forfeited	(50)	3.84 to 3.87	(90)	2.12 to 2.30
Outstanding as at December 31	**2,485**	**2.12 to 3.87**	2,430	2.12 to 3.25

The number outstanding, the weighted average remaining life and weighted average exercise prices of SARs at December 31, 2017 were as follows:

Exercise price *(CDN$)*	**Number outstanding** *(000)*	**Weighted average remaining contractual life** *(years)*	**Number exercisable** *(000)*	**Weighted average exercise price** *(CDN$)*
2.12 to 2.30	1,660	0.96	948	2.27
2.32 to 2.70	100	0.01	100	2.70
3.02 to 3.25	410	2.78	200	3.04
3.84 to 3.87	315	4.02	–	3.86
2.12 to 3.87	**2,485**	**1.61**	**1,248**	**2.62**

Restricted Stock Units ("RSUs")	2017 RSUs (000)	2017 Exercise price (CDN$)	2016 RSUs (000)	2016 Exercise price (CDN$)
Outstanding as at January 1	239	0.001	-	0.001
Granted (i)	1,402	0.001	386	0.001
Exercised	(493)	0.001	(147)	0.001
Outstanding as at December 31	**1,148**	**0.001**	239	0.001

(i) A total of 1,402,322 RSUs were granted during the year, of which 1,000,000 RSUs vest quarterly on July 1, 2017, September 30, 2017, December 31, 2017 and March 31, 2018, with the remaining 402,322 vesting on the date of grant. All RSUs have a term of five years.

The number outstanding, the weighted average remaining life and weighted average exercise prices of RSUs at December 31, 2017 were as follows:

Exercise price *(CDN$)*	**Number outstanding** *(000)*	**Number exercisable** *(000)*	**Weighted average remaining contractual life** *(years)*
0.001	160	160	3.01
0.001	988	738	4.28
0.001	**1,148**	**898**	**4.11**

As SARs and RSUs are settled in cash, they are re-valued at each reporting date using the Black-Scholes option pricing model with the resulting liability being recognized in trade and other payables. In the valuation of stock appreciation rights and restricted stock units at the reporting date, the following assumptions have been made: a risk free rate of interest of 1.0%, stock volatility of 32.4% to 53.3%; 0% dividend yield; 5% forfeiture; a closing stock price of CDN$5.00 per share.

	AS AT DECEMBER 31	
US$'000	**2017**	2016
SARs	**4,339**	2,495
RSUs	**3,555**	682
	7,894	3,177

As at December 31, 2017, a total accrued liability of US$7.9 million (2016: US$3.2 million) has been recognized in relation to SARs and RSUs which is included in other payables. The Company recognized an expense for the year of US$6.6 million (2016: US$2.6 million) in general and administrative expenses.

17 EARNINGS PER SHARE

	AS AT DECEMBER 31	
(000)	**2017**	2016
Outstanding shares		
Weighted average number of Class A and Class B shares	**34,858**	34,857
Weighted average diluted number of Class A and Class B shares	**34,858**	34,857

The calculation of basic earnings per share is based on a net loss for the year of US$2.5 million (2016: net income US$2.2 million) and a weighted average number of Class A and Class B shares outstanding during the period of 34,857,528 (2016: 34,856,432).

18 RELATED PARTY TRANSACTIONS

One of the non-executive Directors is counsel to a law firm that provides legal advice to the Company and its subsidiaries. For the year ended December 31, 2017 US$0.9 million (2016: US$0.2 million) was incurred by this firm for services provided.

As at December 31, 2017 the Company has a total of US$0.5 million (2016: US$0.1 million) recorded in trade and other payables in relation to the related parties.

Notes to the Consolidated Financial Statements

19

CONTRACTUAL OBLIGATIONS & COMMITTED CAPITAL INVESTMENTS

Protected Gas

Under the terms of the Gas Agreement for the Songo Songo project ("Gas Agreement"), in the event that there is a shortfall/insufficiency in Protected Gas as a consequence of the sale of Additional Gas, the Company is liable to pay the difference between the price of Protected Gas (US$0.55/MMbtu escalated) and the price of an alternative feedstock multiplied by the volumes of Protected Gas up to a maximum of the volume of Additional Gas sold (176.4 Bcf as at December 31, 2017). The Company did not have a shortfall during the reporting period and does not anticipate a shortfall arising during the term of the Protected Gas delivery obligation to July 2024.

Terms of the Gas Agreement were modified by the Amended and Restated Gas Agreement ("ARGA") which was initialed by all parties but remains unsigned. The unsigned ARGA provides clarification of the Protected Gas volumes and removes all terms dealing with the security of the Protected Gas and contract terms dealing with the consequences of any insufficiency are dealt with in a new Insufficiency Agreement ("IA"). As at the date of this report, the ARGA remains an initialed agreement only and the IA is unsigned. In certain respects, the parties thereto are conducting themselves as though the ARGA is in effect however no formal agreement has been reached on providing additional security in the event of an insufficiency of Protected Gas. The Company is actively monitoring the reservoir and, supported by the report of its independent engineers, does not anticipate that a liability will occur in this respect. Management does not foresee a material risk with the conduct of the Company's business with an unsigned ARGA or IA at this time.

Additional Gas Plan 2 ("AGP2")

During Q3 2017 the Company, through its subsidiary PAET received approval of the AGP2 from the ME which allows PAET to produce and sell increased volumes of Additional Gas. This can be achieved through the Songas infrastructure and by accessing the NNGIP infrastructure. Wells SS-10, SS-11, and SS-12 have been identified for possible connection to the NNGIP infrastructure subject to finalizing a new gas sales agreement with TPDC for incremental gas sales.

Re-Rating Agreement

In 2011 the Company signed a re-rating agreement with TANESCO, TPDC and Songas (the "Re-Rating Agreement") which evidenced an increase to the gas processing capacity of the Songas facilities to a maximum of 110 MMcfd (the pipeline and pressure requirements at the Ubungo power plant restrict the infrastructure capacity to a maximum of 102 MMcfd). Under the terms of the Re-Rating Agreement, the Company paid additional compensation of US$0.30/mcf for sales between 70 MMcfd and 90 MMcfd and US$0.40/mcf for volumes above 90 MMcfd by issuing credit notes to TANESCO. This was in addition to the tariff of US$0.59/mcf payable to Songas as set by the energy regulator, EWURA. In May 2016 the Company notified TANESCO and Songas that the additional compensation would no longer be paid effective June 2016. This additional compensation was always intended to be temporary in nature until such time as Songas applied to EWURA to obtain approval of a new tariff for the processing of volumes over 70 MMcfd. The PGSA provides for passing on to TANESCO any tariff to be charged to the Company.

The parties are seeking to resolve the status of the re-rating agreement. The processing capacity at the Songas facilities remains unaltered and is fully available for utilization by the Company. This capacity is in addition to the capacity available within the NNGIP infrastructure which PAET intends to utilize now that AGP2 has been approved.

Under the terms of this agreement, the Company agreed to indemnify Songas for damage to its facilities caused by the re-rating, up to a maximum of US$15.0 million, but only to the extent that this was not already recovered through TANESCO's or Songas' insurance policies.

Portfolio Gas Supply Agreement ("PGSA")

On June 17, 2011, a long term PGSA was signed (to June 2023) between TANESCO (as the buyer) and the Company and TPDC (collectively as the seller). Under the PGSA, the seller is obligated, subject to infrastructure capacity, to sell a maximum of approximately 36 MMcfd for use in any of TANESCO's current power plants except those operated by Songas at Ubungo. Under the agreement, the basic wellhead price of approximately US$2.98/mcf increased to US$3.04/mcf on July 1, 2017. Any volumes of gas delivered under the PGSA in excess of 36 MMcfd are subject to a 150% increase in the basic wellhead gas price. In December 2017 notice was given by TANESCO to reduce the maximum daily quantity under the PGSA from 36 to 26 MMcfd effective January 2018.

Operating leases

The Company has two office rental agreements, one in Dar es Salaam, Tanzania and one in Winchester, United Kingdom. The agreement in Dar es Salaam was entered into on November 1, 2015 and expires on October 31, 2019 at an annual rent of US$0.4 million. The agreement in Winchester expires on September 25, 2022 and is at an annual rental of US$0.1 million per annum. The costs of these leases are recognized in the general and administrative expenses.

Capital Commitments

Italy

The Company has an agreement to farm in on Central Adriatic B.R268.RG Permit offshore Italy. The farm-in commits the Company to fund 30% of an appraisal well up to a maximum of US$11.5 million to earn a 15% working interest in the permit. Thereafter, the Company will fund all future costs relating to the well and the permit in proportion to its participating interest. The Company has also agreed to pay fifteen per cent (15%) of the back costs in relation to the well up to a maximum of US$0.5 million. Changes in Italian environmental legislation in late 2015 have resulted in the development of this permit being postponed until the development plan is approved. As at the date of this report, the Company has no further capital commitments in Italy.

Tanzania

There are no contractual commitments for exploration or development drilling or other field development either in the PSA or otherwise agreed which would give rise to significant capital expenditure at Songo Songo. Any significant additional capital expenditure in Tanzania is discretionary.

The completion of the offshore component of Phase A of the Development Program in February 2016 improved field deliverability and provided sufficient natural gas production to fill the Songas plant and pipeline to capacity for the greater portion of the remaining life of the production licence. With the signing of AGP2, the Company is planning to continue with the completion of Phase A of the Development Program that includes a refrigeration unit and well workovers with an estimated cost of US$22 million. A portion of the costs are for workovers on wells SS-3 and SS-4 and it is expected that Songas, the owner of the wells, will fund the costs for these workovers. Assuming Songas covers the costs for workovers of SS-3 and SS-4, the Company's estimated net cost is US$13.3 million.

During 2017 the Company connected well SS-11 to the NNGIP infrastructure and is currently finalizing commercial terms with TPDC for the sale of incremental gas volumes through the NNGIP.

At the date of this report, the Company has no significant outstanding contractual commitment and has no outstanding orders for long lead items related to any capital programs.

Notes to the Consolidated Financial Statements

20 CONTINGENCIES

Upstream and downstream activities

The Petroleum Act, 2015 (the "Petroleum Act") provides TPDC with exclusive rights over the distribution of gas in Tanzania. The Petroleum Act has grandfathering provisions upholding the rights of the Company to develop and market natural gas produced under the PSA as it was signed prior to the Petroleum Act coming into effect in 2015. However, it is still unclear how the provisions of the Petroleum Act will be interpreted and implemented regarding upstream and downstream activities and the Company is uncertain regarding the potential impact on its business in Tanzania.

On October 7, 2016 the Government of Tanzania issued the Petroleum (Natural Gas Pricing) Regulation made under Sections 165 and 258 (I) of the Petroleum Act. Article 260 (3) of the Petroleum Act preserves the Company's pre-existing right with TPDC to market and sell Additional Gas together or independently on terms and conditions (including prices) negotiated with third party Natural Gas customers. The impact of the Natural Gas Pricing Regulation, if any, cannot be determined at this time.

TPDC Back-in

TPDC has the right under the PSA to 'back in' to the Songo Songo field development and convert this into a carried working interest in the PSA. The current terms of the PSA require TPDC to provide formal notice in a defined period and contribute a proportion of the costs of any development, sharing in the risks in return for an additional share of the gas. To date, TPDC has not contributed any costs.

For the purpose of the reserves certification as at December 31, 2017, it was assumed that TPDC will elect to 'back-in' for 20% for all future new drilling activities within the prescribed period as determined by the current development plan and this is reflected in the Company's net reserve position.

Cost recovery

TPDC conducted an audit of the historic Cost Pool and in 2011 disputed approximately US$34 million of costs that had been recovered from the Cost Pool from 2002 through to 2009. In 2014 a substantial portion of the disputed costs were agreed to be cost recoverable by TPDC. Under the dispute mechanism outlined in the PSA, TPDC are to appoint an independent specialist to assist the parties in reaching agreement on costs that are still subject to dispute. In 2014, prior to appointing an independent specialist, TPDC suspended the process. There have been no further developments regarding the dispute since this suspension and at the time of writing this report no such specialist has been appointed. If the matter is not resolved to the Company's satisfaction, the Company intends to proceed to arbitration via the International Centre for Settlement of Investment Disputes ("ICSID") pursuant to the terms of the PSA.

Taxation

		Tax dispute	Disputed amounts US$'million		
Area	**Period**	**Reason for dispute**	**Principal**	**Interest**	**Total**
Pay-As-You-Earn ("PAYE") tax	2008-10	PAYE tax on grossed-up amounts in staff salaries which are contractually stated as net.	0.3	–	0.3 (1)
Withholding tax ("WHT")	2005-10	WHT on services performed outside of Tanzania by non-resident persons.	1.1	0.7	1.8 (2)
Income Tax	2008-15	Deductibility of capital expenditures and expenses (2009 and 2012), additional income tax (2008, 2010, 2011 and 2012), tax on repatriated income (2012), foreign exchange rate application (2013 and 2015) and underestimation of tax due (2014).	29.6	10.0	39.6 (3)
VAT	2008-10	Output VAT on imported services and SSI Operatorship services.	2.7	2.8	5.5 (4)
			33.7	13.5	47.2

Management, with the advice from its legal counsels, has reviewed the Company's position on the objections and appeals related to the disputed amounts and has concluded that no provision is required with regard to these matters and that the maximum exposure is US$47.2 million (2016: US$34.6 million).

(1) In 2015 PAET appealed the Tax Revenue Appeals Board ("TRAB") ruling that PAET is liable to pay PAYE on grossed-up amounts on staff salaries. TRAB waived interest assessed thereon. The Tax Revenue Appeals Tribunal ("TRAT") upheld TRAB decision which ruled in favour TRA on principal tax demanded but waived interest assessed thereon. In 2017 PAET appealed the TRAT ruling to the Court of Appeal of Tanzania ("CAT"). PAET is awaiting CAT hearing date to be set;

(2) (a) 2005-2009 (US$1.7 million): In 2016 TRA filed an application for review of the Court of Appeal (CAT) decision in favour of PAET that no WHT was required on services performed outside Tanzania by non-resident persons and later filed another application for leave to amend its earlier application. At the CAT hearing in Q1 2017, TRA withdrew their second application for review. In Q2 2017 the CAT accepted PAET's preliminary objection against the TRA application. On July 28, 2017 TRA filed another Application for extension of time, under the certificate of urgency, for their application for CAT leave to review its judgement. Subsequent to year end CAT ruled in favour of PAET's preliminary objection. TRA still has the right to amend and re-file its application;

(b) 2010 (US$0.1 million): TRAB is awaiting a ruling from the review by the Court of Appeal on the 2005-2009 case which would influence TRAB's decision on this matter accordingly;

(3) (a) 2009 (US$2.6 million): In 2015 TRAB ruled against PAET with respect to timing of deductibility of capital expenditures and other expenses (US$1.8 million). In Q2 2017 PAET lost an appeal at TRAT and subsequently filed an appeal to CAT and is awaiting a hearing date to be set. In July 2017 TRA sent PAET an amended assessment claiming additional taxes, interest and penalties (US$0.8 million). PAET has objected to the assessment for being time-barred and arbitrary and is awaiting a TRA response;

(b) 2008 (US$0.6 million): In Q2 2017 TRA issued an adjusted assessment which accepted PAET's position that there was no tax payable for the year. The assessment, however, did not recognize a tax loss carried forward of US$1.8 million (with tax impact of US$0.6 million). PAET has objected to the assessment for being time-barred, incorrect and arbitrary;

(c) 2011 (US$2.0 million): In Q2 2017 PAET filed an appeal at TRAB against a TRA assessment with respect to timing of deductibility of capital expenditures and other expenses (US$1.8 million). PAET is awaiting a TRAB hearing date. PAET is also awaiting a TRA response on an objection of another assessment with respect to alleged late filing penalty and under-estimation of interest (US$0.2 million) raised for the year;

(d) 2010 (US$2.4 million): PAET filed an appeal with TRAB against a TRA assessment with respect to timing of deductibility of capital expenditures and other expenses as well as underestimation of interest and penalty amounts. PAET is awaiting a hearing date to be scheduled;

(e) 2013 (US$6.6 million): In 2016 PAET filed objections to a TRA assessment with respect to foreign exchange rate application and is awaiting a response. PAET received TRA assessments for corporation tax (US$0.9 million) which disallowed certain operating costs included in the tax returns and tax on repatriated income (US$5.7 million). PAET has objected to the assessments due to being time-barred and without merit. PAET has also appealed to TRAB the TRA decision not to exercise its administrative powers judiciously to grant the waiver on one-third deposit required to be paid to admit the objection and is awaiting the hearing date to be scheduled;

(f) *2012 (US$15.8 million): In 2016 TRA issued two assessments with respect to understated revenue, timing of deductibility of capital expenditures, expenses and tax on repatriated income. PAET filed an appeal with TRAB against the TRA decision to deny PAET a waiver for payment of a deposit required for its objection to be admitted but was granted a partial waiver only. PAET appealed the decision demanding full waiver of the deposit and also filed an application for the stay of execution with TRAT in response to the TRA demand notice for the payment of the deposit ruled by TRAB. TRAT upheld the TRAB decision for partial waiver. Management has decided to appeal the decision by the TRAT and has fourteen days from the date of TRAT decision to file a Notice of Appeal;*

(g) *2014 (US$9.2 million): In 2016 TRA issued an assessment of US$3.3 million with respect to underestimation of tax due based on the provisional quarterly payments made by PAET, delayed filings of returns and late payments. PAET filed objections to the assessments and is awaiting a response. PAET has also appealed to TRAB the TRA decision not to exercise its administrative powers judiciously to grant the waiver on one-third deposit required to be paid to admit the objection and is awaiting the hearing date to be scheduled. TRA issued two additional assessments for the year for corporation tax of US$3.1 million and tax on repatriated income US$2.8 million. PAET has objected the assessments and is awaiting TRA response;*

(h) *2015 (US$0.4 million): In 2016 TRA issued a self-assessment. PAET filed an objection to the assessment with respect to foreign exchange rate application and is awaiting a response;*

(4) (a) *2008-2010 (US$5.4 million): In 2016 TRA responded to PAET's objection filed in 2014 and issued an assessment in respect of output VAT on imported services and SSI Operatorship services. PAET filed an appeal with TRAB against the TRA assessment and is awaiting a hearing date to be scheduled;*

(b) *2012-2014 (US$0.1 million): TRA issued an assessment for VAT on other income that PAET had paid. PAET has objected the assessment and is awaiting TRA response.*

21 DIRECTORS AND OFFICERS EMOLUMENTS

US$'000	**Year**	**Base**	**Bonus**	**Stock based compensation expense**	**Total**
Directors	**2017**	**600**	**–**	**863**	**1,463**
Directors	2016	535	–	940	1,475
Officers	**2017**	**1,668**	**280**	**5,372**	**7,320**
Officers	2016	1,642	280	1,152	3,074

The table above provides information on compensation relating to the Company's officers and directors. Three officers and four non-executive directors comprised the key management personnel during the year ended December 31, 2017 and 2016.

22 CHANGE IN NON-CASH OPERATING WORKING CAPITAL

US$'000	YEARS ENDED DECEMBER 31 2017	2016
Decrease (increase) in trade and other receivables	**5,310**	(4,160)
Increase in tax recoverable	**–**	(883)
(Increase) decrease in prepayments	**(215)**	467
Increase (decrease) in trade and other payables	**22,485**	(716)
(Decrease) increase in tax payable	**(2,172)**	117
Increase in long-term receivable	**(2,153)**	(12,380)
	23,255	(17,555)

23 SUBSEQUENT EVENTS

On January 16, 2018 the Company sold 7.933 per cent (7,933 Class A common shares) of its subsidiary, PAEM, to Swala (PAEM) Limited a wholly owned subsidiary of Swala Oil & Gas (Tanzania) plc. ("Swala") for US$25.8 based on an enterprise value of US$325 million as at January 1, 2017 (the "effective date"). After adjusting the enterprise value for long term debt of US$60 million, the net sales price for the 7.933 per cent was US$21.1 million. The consideration received by the Company was US$16.2 million cash (US$17.1 million less a purchase price adjustment of US$0.9 million reflecting Swala's share of cash flow from the effective date of the transaction until closing) and US$4.0 million of Swala convertible preferred shares. The transaction provides Swala with the right to acquire up to 40% of PAEM at the net value of US$265 million adjusted for Swala's share of cash flow from the effective date until the next closing date. The Company has granted an extension of this right to May 11, 2018.

On January 18, 2018 the Company declared a dividend of CDN$0.60 per share on each of its class A voting and class B subordinate voting shares to holders of record as of January 31, 2018 paid on February 7, 2018.

Corporate Information

Board of Directors

W. David Lyons
Chairman and
Chief Executive Officer

Queensway
Gibraltar

David W. Ross
Non-Executive
Director

Calgary, Alberta
Canada

William H. Smith
Non-Executive
Director

Calgary, Alberta
Canada

E. Alan Knowles
Non-Executive
Director

Calgary, Alberta
Canada

Glenn D. Gradeen
Non-Executive
Director

Calgary, Alberta
Canada

Officers

W. David Lyons
Chairman and
Chief Executive Officer

Queensway
Gibraltar

Blaine Karst
Chief Financial Officer

Calgary, Alberta
Canada

David K. Roberts
Vice President of Operations

Kansas City, Missouri
United States of America

Operating Office

PanAfrican Energy
Tanzania Limited

Oyster Plaza Building, 5th Floor
Haile Selassie Road
P.O. Box 80139, Dar es Salaam
Tanzania
Tel: + 255 22 2138737
Fax: + 255 22 2138938

Registered Office

Orca Exploration
Group Inc.

P.O. Box 146
Road Town
Tortola
British Virgin Islands, VG110

Investor Relations

W. David Lyons
Chairman and
Chief Executive Officer

WDLyons@orcaexploration.com
www.orcaexploration.com

International Subsidiaries

**PanAfrican Energy
Tanzania Limited**

Oyster Plaza Building, 5th Floor
Haile Selassie Road
P.O. Box 80139, Dar es Salaam Tanzania
Tel: + 255 22 2138737
Fax: + 255 22 2138938

**PAE PanAfrican
Energy Corporation**

1st Floor
Cnr Desroches/St Louis
Port Louis
Mauritius
Tel: + 230 207 8888
Fax: + 230 207 8833

Orca Exploration Italy Inc.

**Orca Exploration Italy
Onshore Inc.**

P.O. Box 3152,
Road Town
Tortola
British Virgin Islands

Engineering Consultants

McDaniel & Associates
Consultants Ltd.
Calgary, Canada

Auditors

KPMG LLP
Calgary, Canada

Website

orcaexploration.com

Lawyers

Burnet, Duckworth
& Palmer LLP
Calgary, Canada

Transfer Agent

AST Trust Company
Calgary, Alberta, Canada

ORCA

ORCA

www.orcaexploration.com