ORCA EXPLORATION GROUP INC.

2018 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	Proved reserves
MMcf	Millions of standard cubic feet	2P	Proved and probable reserves
Bcf	Billions of standard cubic feet	3P	Proved, 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 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 $000 unless indicated otherwise)	YEAR ENDED DECEMBER 31 **2018**	2017	% Change 2018 vs 2017
OPERATING			
Daily average gas delivered and sold *(MMcfd)*			
Additional Gas	**39.9**	41.6	(4)%
Industrial	**13.0**	12.6	3%
Power	**26.9**	29.0	(7)%
Average price *($/mcf)*			
Industrial	**8.26**	7.71	7%
Power	**3.68**	3.60	2%
Weighted average	**5.17**	4.84	7%
Operating netback *($/mcf)* [1]	**2.76**	3.00	(8)%
RESERVES			
Additional Gas Gross Recoverable Reserves *(Bcf)*			
Proved	**261**	307	(15)%
Probable	**32**	73	(56)%
Proved plus probable	**293**	380	(23)%
Net Present Value, discounted at 10% *($ millions)* [2]			
Proved	**252**	269	(6)%
Proved plus probable	**294**	326	(10)%
FINANCIAL			
Revenue	**57,766**	60,832	(5)%
Net cash flows from operating activities	**28,752**	48,154	(40)%
per share - basic and diluted *($)*	**0.82**	1.38	(40)%
Net income (loss) attributable to shareholders	**13,270**	(2,500)	n/m
per share - basic and diluted *($)*	**0.38**	(0.07)	n/m
Adjusted funds flow from operations [1]	**19,255**	16,742	15%
per share - basic and diluted *($)*	**0.55**	0.48	15%
Capital expenditures (excluding transfers)	**5,843**	1,545	278%

(Expressed in $000 unless indicated otherwise)	AS AT DECEMBER 31 **2018**	2017	
Working capital (including cash)	**84,182**	69,575	21%
Cash	**64,660**	122,322	(47)%
Investment in short-term bonds	**66,837**	–	n/m
Long-term loan	**53,900**	58,518	(8)%
Outstanding Shares ('000)			
Class A	**1,750**	1,750	0%
Class B	**33,506**	33,506	0%
Total shares outstanding	**35,256**	35,256	0%
Weighted average Class A and Class B shares	**35,256**	34,858	1%

[1] *Please refer to Non-GAAP measures section of the Management Discussion and Analysis ("MD&A") for additional Information. Certain prior year amounts for adjusted funds flow from operations have been reclassified to conform with the current year presentation.*

[2] *In accordance with the Production Sharing Agreement ("PSA") with the Tanzanian Production Development Corporation ("TPDC") and the Government of Tanzania ("GoT") in the United Republic of Tanzania 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. Any capitalized terms otherwise not defined within the Highlights are defined in the MD&A as set forth on page 13.*

2018 Operating Highlights

- The Company's revenue for the year decreased by 5% to $57.8 million from $60.8 million in the prior year. The decrease is the result of lower power sales volumes, higher TPDC Profit Gas share and a lower current income tax adjustment. Additional Gas deliveries and sales for the year averaged 39.9 million standard cubic feet per day ("MMcfd") a decrease of 4% over 41.6 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 the Tanzanian Electric Supply Company Limited ("TANESCO"). The decrease in volumes was partially offset by a 7% rise in the weighted average price for 2018 to $5.17/mcf from $4.84/mcf in the prior year.
- Total proved reserves for Additional Gas decreased 15% to 261 Bcf from 307 Bcf in the prior year and total proved plus probable reserves ("2P") decreased 23% to 293 Bcf from 380 Bcf in the prior year. The decrease is a consequence of 2018 Additional Gas production of 14.6 Bcf, lower anticipated forecasted sales and the reduction in the effective ownership interest in the gross property reserves due to the sale of a 7.9% non-controlling interest in a subsidiary, PAE PanAfrican Energy Corporation ("PAEM"). The net present value of the estimated future cash flows from the 2P reserves at a 10% discount rate ("NPV10") decreased by 10% to $294.4 million from $326.1 million in the previous year. The decrease is predominately the result of recognizing a non-controlling interest in the dividend stream from PAEM in arriving at the present value and the decline in the forecast sales being offset by the removal of the SSN-1 well from the future development costs in the 2P life of licence valuation. 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 income attributable to shareholders of $13.3 million for the year compared to a net loss attributable to shareholders of $2.5 million in the prior year. The increase in net income attributable to shareholders for the year was primarily a result of the increase in finance income as a result of the reversal of the provision for doubtful accounts of $15.9 million related to the collection of TANESCO arrears previously provided for being offset by increased stock based compensation costs and increased interest expense.
- The Company's net cash flows from operating activities for the year decreased by 40% to $28.8 million from $48.2 million in the prior year. The decrease for the year from the prior year is primarily a consequence of the payments for stock based compensation, together with the decrease in the cash inflow associated with changes in non-cash working capital.
- The Company's adjusted funds flow from operations for the year ended December 31, 2018 increased by 15% to $19.3 million (2017: $16.7 million). The increase between years is primarily a result of reduced general and administration expenses ($1.2 million) and an increase in interest income on bonds ($1.3 million) for 2018 compared to 2017. The decrease in revenue between years was offset by the decrease in current corporate income tax expense.
- Working capital increased 21% to $84.2 million compared to $69.6 million as at December 31, 2017. The increase is primarily due to the cumulative cash collections from TANESCO for current deliveries and arrears offset by an increase in stock based compensation during the period. The closing cash at December 31, 2018 was $64.7 million (December 31, 2017: $122.3 million). The decrease in cash is primarily a result of the investment in short-term bonds of $66.8 million at December 31, 2018 (December 31, 2017: $ nil). The Company's intention is to hold the bond investments to maturity.
- At December 31, 2018 the current receivable from TANESCO was $ nil (December 31, 2017: $ nil). During the year, the amounts received from TANESCO continued to be in excess of the revenue recognized for gas sales to TANESCO. As a result, during 2018 $15.9 million of cumulative excess receipts over sales invoiced was allocated to the long-term arrears together with the associated reversal of the provision for doubtful accounts. The TANESCO long-term receivable at December 31, 2018 was $58.5 million (with a provision of $58.5 million) compared to $74.4 million (with a provision of $74.4 million) at December 31, 2017. Subsequent to December 31, 2018 the Company has invoiced TANESCO $15.6 million for 2019 gas deliveries and TANESCO has paid the Company $18.0 million.
- On January 16, 2018 the Company sold 7.9% of PAEM to a wholly owned subsidiary of Swala Oil & Gas (Tanzania) plc., ("Swala") for a net sales price of $21.0 million based on a net enterprise value of $265.0 million as at January 1, 2017 (the "effective date"). The consideration received by the Company was $15.7 million in cash ($17.0 million less a purchase price adjustment of $1.3 million reflecting Swala's share of cash flow from the effective date of the transaction until closing) and $4.0 million of Swala convertible preference shares. The agreement provided Swala with the right to acquire up to a maximum of 40% of PAEM based on the same terms and conditions. Subsequent to December 31, 2018 the Company terminated this right.

Strong balance sheet and financially robust

Orca entered 2019 in a financially robust position after a year of positive net cash flow from operations of $28.8 million and net income attributable to shareholders of $13.3 million. With a strong balance sheet, cash and short-term bonds of $131 million and increasing gas sales volumes, the Company believes it is well positioned to grow over the coming years through our stated strategy of maximising the potential of our integrated gas project in Tanzania, diversifying our asset base and increasing liquidity in Orca's equity.

No infrastructure constraints and increasing gas demand

The Songo Songo reservoir in Tanzania continues to perform extremely well. Since we commenced operations in 2004, according to the report prepared by our independent reserve evaluator, McDaniel and Associates Consultants Ltd ("McDaniel") effective December 31, 2018 (the "McDaniel Report"), 383 Bcf (64 MMboe) of natural gas has been produced from the field of which 191 Bcf relates to Additional Gas that was sold to industrial and power customers in Dar es Salaam. The use of indigenous reliable natural gas and the displacement of imported fuel has had a significant beneficial impact on the Tanzanian economy.

With the field work programme that was completed by the Company in 2016 and the construction of the National Natural Gas Infrastructure ("NNGI") by the TPDC and the GoT, the Company believes it is currently in a strong position to meet incremental increases in demand on a timely basis. There are now two separate systems to process and transport the Songo Songo gas to Dar es Salaam and no infrastructure constraints are anticipated for the foreseeable future.

Over the last year, 160 MWs of new gas fired generation capacity was commissioned and there was an increase in industrial demand when Dangote Cement started to consume higher volumes of gas at their new facility in the south of Tanzania. This combined with the need to balance the network has led to Orca's Additional Gas sales increasing to an average of 62 MMcfd for the first two months of 2019, compared to an average of 40 MMcfd in 2018. It is expected that an additional 180 MWs of gas fired generation capacity will be commissioned in stages over the next six to eighteen months increasing gas demand by 35 MMcfd at maximum load.

Shortly before year end, Orca's subsidiary, Pan African Energy Tanzania Limited ("PAET") signed a short-term sales agreement with the TPDC and TANESCO for the immediate supply of gas to TANESCO of up to 35 MMcfd. These additional volumes are being processed and transported through the NNGI and are expected to allow TANESCO to generate increased and more stable power to meet emerging demand. PAET and TPDC have submitted a long-term gas sales agreement to the Ministry for approval. We look forward to working with all parties to ensure that affordable indigenous gas continues to be a significant proportion of the energy mix in Tanzania.

261 Bcf (47 MMboe) of gross proved reserves

As at December 31, 2018 McDaniel assessed in the McDaniel Report that the gross proved (1P) and proved plus probable (2P) Songo Songo conventional natural gas reserves available to Orca to the end of the licence period are 261 Bcf and 293 Bcf, respectively. This year we determined that there was no economic justification for drilling the Songo Songo North field prior to the end of the licence period and accordingly no reserves have been included for this reservoir in the 2P reserves. This will be revisited if PAET secures a licence extension.

To meet the increasing gas demand, we are in the process of completing the procurement and installation of a refrigeration unit to maintain deliverability through the Songas gas processing and pipeline system and have commenced the design work for compression that will be required in 2021 to maintain gas at sufficient pressure to maximise throughput. In addition, the Company currently plans to workover wells SS-3 and SS-4 and to recomplete SS-10 with chrome production tubing to maintain deliverability and increase operating life to the end of the licence period.

[1] *Company gross reserves are the total of the Company's working interest share in reserves before deduction of royalties owned by others and without including any royalty interests of the Company and are based on the Company's 92.07 percent ownership interest in the reserves following the transaction with Swala Oil & Gas (Tanzania) plc described in Orca's reports relating to reserves data and other oil and gas information under National Instrument 51-101, which are available on its profile on SEDAR at www.sedar.com.*

CEO's Report to Shareholders

A high calibre Tanzanian team

We are proud that over the years our Company has developed a deep technical operating expertise in our Tanzanian staff. The wells and gas processing facility on Songo Songo Island are entirely managed and operated by local workers on a rotational basis and there are currently only three expats working on our team in the country. Education is central to our Corporate Social Responsibility programme and in 2018 we constructed several classrooms in the Kilwa district, rolled out an intensive English learning programme in 28 schools and provided college funding to a number of students on Songo Songo Island.

Short term targets

Orca has revitalised the management team to deliver on its cash flow and profitability targets. We have provided guidance that we anticipate Additional Gas sales volumes will be between 60 – 75 MMscfd in 2019. This will be accompanied by a drive to reduce general and administrative costs despite an increase in headcount at the corporate level. We also plan to work towards resolving several outstanding issues with respect to cost recovery, tax and PSA terms that are documented in the notes to the financial statements.

While we remain committed to developing and maximising the value of our existing operations in Tanzania, we also see potential to diversify our asset base to increase cashflows and shareholder liquidity. We are currently evaluating several proved reserve opportunities where funding could be deployed to optimise development plans that are expected to be accretive for our shareholders. A business development team has been recruited to evaluate and, if appropriate, execute on these transactions..

Initiation of quarterly dividend

As previously announced, Orca will be paying a dividend of CDN$0.05 per Class A Common Voting Share of the Company and CDN$0.05 per Class B Subordinate Voting Share of the Company payable to the holders of Class A Shares and Class B Shares of record on each of March 31, 2019 and payable on or about April 30, 2019. In the future, the Board expects to evaluate the appropriateness of declaring and paying cash dividends on a quarterly basis.

David Lyons

The position the Company finds itself today is in no small thanks down to the leadership and entrepreneurial spirit demonstrated by our former Chairman and CEO, David Lyons. Mr Lyons had the foresight to identify a stranded gas field in Tanzania in 1991 and to work with the GoT, the World Bank, the AIG African Infrastructure Fund L.L.C. and other interested parties to develop the Songo Songo Gas Development and Power Generation Project. This remains a unique and highly successful project that has stood the test of time and is testament to David’s commitment, resolve and vision.

Gas Reserves

The Company's natural gas reserves as at December 31, 2018 for the period to the end of its licence in October 2026 were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel") 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 prepared by McDaniel (the "McDaniel Report") is dated April 4, 2019 with the effective date of December 31, 2018. A reserves committee of the board of directors 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 an 15% decrease in Songo Songo's Total Proved Additional Gas reserves with a total Additional Gas production of 14.6 Bcf during the year. There has been a 23% decrease in the Proved plus Probable Additional Gas reserves on a gross company basis.

A summary of the remaining Additional Gas reserves are presented below:

	2018		2017	
Songo Songo Additional Gas reserves *(Bcf)*	**Gross** [1]	**Net** [2]	Gross	Net
Independent reserves evaluation				
Proved producing	**227.6**	**142.3**	295.9	183.3
Proved developed non-producing	**33.5**	**18.8**	10.7	6.0
Proved undeveloped	**–**	**–**	–	–
Total proved (1P)	**261.1**	**161.1**	306.6	189.3
Probable	**31.7**	**17.8**	73.5	54.4
Total proved and probable (2P)	**292.8**	**178.9**	380.1	243.7

[1] *Gross equals the gross reserves that are available for the Company based on its effective ownership interest.*
[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 before and after tax of the Songo Songo reserves are as follows:

	2018			2017		
$'millions	***5%***	***10%***	***15%***	*5%*	*10%*	*15%*
Proved producing	**272.0**	**225.5**	**190.3**	327.6	262.6	215.3
Proved developed non-producing	**35.4**	**26.2**	**19.8**	10.1	6.9	4.8
Proved undeveloped	**–**	**–**	**–**	–	–	–
Total proved (1P)	**307.4**	**251.7**	**210.1**	337.7	269.5	220.1
Probable	**51.1**	**42.7**	**36.1**	71.0	56.6	46.3
Total proved and probable (2P)	**358.5**	**294.4**	**246.2**	408.7	326.1	266.4

There has been a 10% decrease in the 2P present value at a 10% discount basis from $326.1 million to $294.4 million. The decrease is predominately the result of recognizing Swala non-controlling interest in the dividend stream from PAEM in arriving at the present value and the decline in the forecast sales being offset by the removal of the SSN-1 well from the future development costs in the 2P valuation.

For the purpose of calculating the Gross Additional Gas reserves, McDaniel has assumed in its 2P case that 81 Bcf (2017: 96 Bcf) or an average of 14.1 Bcf per annum will be required to meet the demands of the Protected Gas users from January 1, 2019 to July 31, 2024. During 2018 the Protected Gas users consumed 14.4 Bcf.

Gas Reserves

	1P Additional Gas price *$/mcf*	1P Gross Additional Gas volumes *MMcfd*	2P Additional Gas price *$/mcf*	2P Gross Additional Gas volumes *MMcfd*
2019	4.07	71.2	4.01	76.2
2020	4.10	81.8	4.17	91.0
2021	4.19	87.4	4.21	102.8
2022	4.29	93.1	4.27	113.8
2023	4.42	93.8	4.40	114.8
2024	4.37	110.8	4.41	132.6
2025	4.31	134.2	4.48	142.5
2026	4.39	134.2	4.71	125.3

Forward-Looking Information

This annual report contains forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation. More particularly, this annual report contains, without limitation, forward-looking statements pertaining to the following: the Company's beliefs regarding its positioning for growth; the outcome of the Company's strategy of maximising the potential of its Tanzanian asset, diversifying its asset base, and increasing the liquidity of its equity; the Company's belief that it is positioned to meet increases in demand; expectations regarding increases in gas fired generation capacity; the procurement and installation of the refrigeration unit in the Songas gas processing and pipeline system; the Company's plans to workover wells SS-3 and SS-4 and recomplete well SS-10; Orca's expectation that Additional Gas sales volumes will be between 60 -75 MMscfd in 2019; and statements regarding quarterly dividends. 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 profitably produced 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, 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. Additionally, 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. Please see the Company's Management Discussion & Analysis for the year ended December 31, 2018 filed on www.sedar.com for a discussion of such risks, uncertainties, and assumptions.

The forward-looking statements contained in this annual report 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.

Oil and Gas Advisory

The Company's conventional natural gas reserves as at December 31, 2018 disclosed herein were evaluated by McDaniel in accordance with the definitions, standards and procedures contained in the COGE Handbook and NI 51-101. The independent reserves evaluations prepared by McDaniel had an effective date of December 31, 2018 and preparation date of April 4, 2019.

The recovery and reserve estimates of the Company's conventional natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 Bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

ORCA EXPLORATION GROUP INC.

2018 MANAGEMENT'S DISCUSSION & ANALYSIS

THIS MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS SHOULD BE READ IN CONJUNCTION WITH THE AUDITED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES FOR THE YEAR ENDED DECEMBER 31, 2018. THIS MD&A IS BASED ON THE INFORMATION AVAILABLE ON APRIL 10, 2019. ALL AMOUNTS ARE REPORTED IN US DOLLARS ("$") UNLESS OTHERWISE NOTED.

NATURE OF OPERATIONS

Orca Exploration Group Inc (the "Company") has as its principal operating asset, an interest in the Production Sharing Agreement ("PSA") with the Tanzanian Production 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 Development Licence Area (the "Songo Songo Gas Field") offshore Tanzania.

The PSA defines the gas produced from the Songo Songo Gas 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 Limited ("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 fuel for its gas turbine electricity generators 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 Gas Field in excess of the Protected Gas requirements ("Additional Gas") until the PSA expires in October 2026.

The Tanzanian Electric Supply Company Limited ("TANESCO") is a parastatal organization which is wholly-owned by the GoT with oversight by the Ministry for Energy ("MoE"). TANESCO is responsible for the majority of 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 hydropower and a more cost-effective alternative to liquid fuels. The Company currently supplies gas directly to TANESCO by way of the Portfolio Gas Supply Agreement ("PGSA") between TANESCO and TPDC 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 42% of the electrical power generated in Tanzania and constitutes 58% 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 consolidated in the financial statements are:

Company	Incorporated	Holding
Orca Exploration Group Inc.	British Virgin Islands	Parent Company
Orca Exploration Italy Inc.	British Virgin Islands	100%
Orca Exploration Italy Onshore Inc.	British Virgin Islands	100%
PAE PanAfrican Energy Corporation ("PAEM")	Mauritius	92%
PanAfrican Energy Tanzania Limited ("PAET")	Jersey	92%
Orca Exploration UK Services Limited	United Kingdom	100%

PRINCIPAL TERMS OF THE PSA AND RELATED AGREEMENTS

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

Obligations and restrictions

(a) The PSA covers two blocks within the Songo Songo Gas Field where there are gas reserves ("Discovery Blocks"). The Company has the right to conduct petroleum operations on the Discovery Blocks, 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 Blocks 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 their related liability by either replacing the Indemnified Volume (as defined in (d) below) at the Protected Gas price with natural gas from other sources; or by paying monetary 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 $0.55/MMbtu escalated) and the amount of transportation revenues previously credited by Songas to the state electricity utility, TANESCO, for the gas volumes.

(d) 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

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

Revenue sharing terms and taxation

(f) 75% of the gross field revenues derived from the Discovery Blocks, 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 MoE, 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 MoE has approved the Additional Gas Plan, then TPDC is deemed not to have elected to participate. 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, 2018, there are no planned drilling activities to the end of the licence.

(g) The Company's long-term gas price to the Power sector as set out in the Amended and Restated Gas Agreement ("ARGA") between the GoT, TPDC and Songas and the PGSA is based on the price of gas at the wellhead. 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, TPDC and Songas are currently finalizing the terms of a long-term gas sales agreement ("GSA") that will ultimately replace the ARGA.

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 Plant 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 $0.30/mcf for sales between 70 MMcfd and 90 MMcfd and $0.40/mcf for volumes above 90 MMcfd by issuing credit notes to TANESCO. This was in addition to the tariff of $0.59/mcf payable to Songas as set by the energy regulator, Energy and Water Regulatory Authority ("EWURA"). Songas terminated the Re-Rating Agreement in 2014 although there remains a disagreement as to its current status.

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 processing capacity at the Songas Plant remains unaltered and is fully available for utilization by the Company along with the additional capacity within the National Natural Gas Infrastructure 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 "NNGI"). 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.

In Q3 2017 the Company received approval of the Additional Gas Plan 2 ("AGP2") from the MoE to produce and sell increased volumes of Additional Gas. This may be achieved through the Songas Infrastructure and by accessing the NNGI. Wells SS-11 and SS-12 are connected to the NNGI and the SS-12 well started flowing gas through the NNGI in December 2018 pursuant to a side letter agreement to the PGSA.

The side letter agreement was entered into with TPDC and TANESCO. The parties agreed to nominate the NNGI on Songo Songo island as a temporary delivery point for up to 35 MMcfd of gas sold to TANESCO under the PGSA. The terms of the side letter agreement are based on a one month term, extendable monthly up to a limit of six months to enable the delivery of gas to sustain power generation by TANESCO until the GSA is approved. On February 11, 2019 the Company and TPDC initialed a GSA, however, there is no guarantee that the GSA will be finalized as it requires further government approvals.

(h) 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.

(i) "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.

(j) The Company is appointed to develop, produce and process Protected Gas and operate and maintain the Songas Infrastructure, including the staffing, procurement, capital improvements, contract maintenance, maintenance of books and records, preparation of reports, maintenance of permits, waste handling, liaison with the GoT 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.

(k) In the event of loss arising from Songas' failure to perform, and the loss is not fully compensated by Songas or through insurance coverage, then the Company is liable to a performance and operational guarantee of $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.

Results for the year ended December 31, 2018

SUMMARY

During the year ended December 31, 2018 the Company started delivering Additional Gas volumes through the NNGI pursuant to the side letter agreement to the PGSA signed in December 2018. The side letter allows for realignment of some TANESCO PGSA sales to be delivered though the NNGI increasing production capabilities that had been previously restricted by Songas Infrastructure capacity limitations. The Company has the ability to increase sales of Additional Gas volumes to industrial customers and to TPDC, subject to approval of the initialed GSA, by utilizing the NNGI and completing the installation of a refrigeration unit for the Songas Plant. The refrigeration unit is scheduled for completion by Q2 2019 and by installing compression before the end of 2021, production volumes can be maintained at 130 MMscfd with the possibility to expand well deliverability to 165 MMscfd by increasing the amount of gas being delivered through NNGI. Volumes to the NNGI are currently being delivered using well SS-12 however well SS-11 is also available for immediate production through the NNGI as it was tied into the NNGI in 2017. Well SS-11 is currently being produced through the Songas Infrastructure.

During the year ended December 31, 2018 the Company commenced construction of the refrigeration unit and completed the flow lines, connection work and tie-in of well SS-12 to the NNGI. Total capital expenditures for the year were $5.8 million (2017: $1.6 million). The 2017 expenditures related to the completion of the platform for well SS-12 and tie-in costs of well SS-11 to the NNGI.

For the year ended December 31, 2018 there was a decrease of 23% from the prior year in proved and probable ("2P") reserve volumes primarily related to gas produced during the year. The decline in forecasted 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 net present value decrease also takes into consideration the sale of a 7.9% non-controlling interest of PAEM in 2018.

The Company's operating revenue increased by 20% to $14.2 million in the quarter ended December 31, 2018 (Q4 2017: $11.8 million) and by 1% to $54.4 million for the year ended December 31, 2018 (2017: $53.7 million). The increase in the quarter is primarily due the increase in the Company share of Profit Gas as the Company sold 44.8 MMcfd (Q4 2017: 38.5 MMcfd). The increase for the year is primarily the consequence of higher industrial sales volumes and prices. Revenue for the quarter ended December 31, 2018 increased by 27% to $13.6 million (Q4 2017: $10.6 million) and decreased by 5% for the year ended December 31, 2018 to $57.8 million (2017: $60.8 million). The revenue increase in the quarter is primarily due to an increase in sales volume. Revenue for the year declined due to a lower tax adjustment which was the result of deferred revenue being released to revenue in Q1 2018.

The Company's net cash flows from operating activities for the quarter ended December 31, 2018 decreased by 68% to $4.1 million (Q4 2017: $12.9 million) and decreased by 40% to $28.8 million for the year ended December 31, 2018 (2017: $48.2 million). The decrease is primarily a result of the exercise of Stock Appreciation Rights ("SARs") and Restrictive Stock Units ("RSUs") in Q1 2018 together with decrease in the cash inflow associated with changes in non-cash working capital compared to the year ended December 31, 2017. The cash inflow associated with non-cash working capital for the year ended December 31, 2017 is the consequence of the increased trade and other creditors in relation to TPDC payable and deferred revenue.

The Company's adjusted funds flow from operations for the quarter ended December 31, 2018 was $6.4 million (Q4 2017: $0.1 million). The increase in adjusted funds flow from Q4 2017 to Q4 2018 is a combination of an increase in gas volume deliveries and the corresponding increase in revenue, the savings in general and administrative expenses and an increase in interest income from bonds. The Company's adjusted funds flow from operations for the year ended December 31, 2018 increased by $2.6 million to $19.3 million (2017: $16.7 million). The increase between years is primarily a result of reduced general and administration expenses ($1.2 million) and an increase in interest income on bonds ($1.3 million). The decrease in 2018 revenue compared to 2017 of $3.1 million was offset by the decrease in current corporate income tax expense of $3.3 million.

The Company recorded a net income attributable to shareholders of $2.8 million in the quarter ended December 31, 2018 (Q4 2017: $4.7 million net loss) and a net income attributable to shareholders of $13.3 million for the year ended December 31, 2018 (2017: $2.5 million net loss). The increase is primarily due to the increase in finance income as a result of the reversal of the provision for doubtful accounts of $15.9 million relating to the collection of TANESCO arrears (previously provided for) together with an overall decrease in general administrative expenses.

On January 16, 2018 the Company sold 7.9 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 $21.0 million based on a net enterprise value of $265 million as at January 1, 2017 (the "effective date"). The net enterprise value is calculated by reducing the agreed enterprise value of $325 million by the long-term debt of $60 million. The consideration received by the Company was $15.7 million cash ($17.0 million less a purchase price adjustment of $1.3 million reflecting Swala's share of cash flow from the effective date of the transaction until closing) and $4.0 million of Swala convertible preferred shares. The preferred shares were issued to the Company on June 18, 2018 and entitle the holder to a 10% per annum distribution payable 15 days after each quarter end commencing from the closing date, January 16, 2018. If Swala fails to make the payment, any unpaid amounts are accrued until December 31, 2021 at which time the Company can request a return of the number of shares sold in PAEM sufficient to cover any unpaid distribution amounts. As at December 31, 2018 the Company has not received any distributions or recorded any amount receivable related to the preference shares.

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; the dividend was paid on February 7, 2018.

The Company once again exited the year in a stable financial position with $84.2 million in working capital (December 31, 2017: $69.6 million), cash and cash equivalents of $64.7 million (December 31, 2017: $122.3 million) and long-term debt of $53.9 million (December 31, 2017: $58.5 million). The reduction in cash is a result of the Company investing $66.8 million in short-terms bonds all denominated in US$. The Company's intention is to hold the bond investments to maturity. The bonds are highly liquid by their nature and may readily be transferred to cash when necessary.

OPERATING VOLUMES

Additional Gas sales volumes for the year ended December 31, 2018 were 14,572 MMcf (2017: 15,199 MMcf) or average daily volumes of 39.9 MMcfd (2017: 41.6 MMcfd). This represents a decrease in average daily volumes of 4% year on year. The decrease in Additional Gas volumes year over year is primarily a result of reduced consumption of natural gas by TANESCO compared to 2017.

Additional Gas sales volumes for the quarter, were 4,123 MMcf (Q4 2017: 3,538 MMcf) or average daily volumes of 44.8 MMcfd (Q4 2017: 38.5 MMcfd), an increase of 17% 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	
	2018	2017	**2018**	2017
Gross sales volume *(MMcf)*				
Industrial sector	**1,194**	1,110	**4,733**	4,594
Power sector	**2,929**	2,428	**9,839**	10,605
Total volumes	**4,123**	3,538	**14,572**	15,199
Gross daily sales volume *(MMcfd)*				
Industrial sector	**13.0**	12.1	**13.0**	12.6
Power sector	**31.8**	26.4	**26.9**	29.0
Total daily sales volume	**44.8**	38.5	**39.9**	41.6

Industrial sector

Industrial sales volumes for the year were 4,733 MMcf (13.0 MMcfd) compared to 4,594 MMcfd (12.6 MMcfd) for the year ended December 31, 2017. The increase is a result of reduced maintenance time at a cement plant in the first half of 2018 compared to the first half of 2017 and increased consumption by customers throughout 2018. Industrial sales volume increased by 8% to 1,194 MMcf (13.0 MMcfd) in the quarter from 1,110 MMcf (12.1 MMcfd) in Q4 2017. The increase is a result of higher sales volumes to existing industrial customers during Q4 2018.

Power sector

Power sector sales volumes decreased by 7% to 9,839 MMcf (26.9 MMcfd) for the year ended December 31, 2018 from 10,605 MMcf (29.0 MMcfd) for the year ended December 31, 2017. Power sector sales volumes increased by 20% to 2,929 MMcf (31.8 MMcfd) in the quarter from 2,428 MMcf (26.4 MMcfd) in Q4 2017.

The decrease in volumes for the year is primarily a result of reduced consumption of gas volumes by TANESCO during the first three quarters of the year offset by increased demand during Q4 2018 with deliveries commencing through the NNGI.

SONGO SONGO DELIVERABILITY

As at December 31, 2018 the Company had a well capacity of approximately 130 MMcfd. Until well SS-12 began producing through the NNGI on Songo Songo Island in December 2018, production had been limited to 97 MMcfd due to a combination of Songas Infrastructure capacity limitations and reservoir pressure decline. With the installation of the refrigeration unit at the Songas Plant scheduled for completion in Q2 2019, well capacity of 130 MMcfd can be sustained until the installation of compression, currently scheduled for completion by the end of 2021. This will provide the ability to expand the level of well capacity from 130 MMcfd to approximately 165 MMcfd by continuing to increase gas produced through the NNGI.

Well SS-12 is currently supplying up to 35 MMcfd of Additional Gas to TANESCO through the NNGI via a side letter agreement to the PGSA. Subject to approval of the initialed GSA, the Company plans to sell Additional Gas volumes directly to TPDC through the NNGI. Well SS-3 is currently suspended and well SS-4 has been shut-in pending the commissioning of the refrigeration unit at the Songas Plant. The Company may undertake workovers on both the wells in the future together with well SS-10.

As at December 31, 2018 well SS-11 is tied into both the Songas Plant and the NNGI while well SS-12 is only tied into the NNGI. The facilities for the connection of well SS-10 to the NNGI are available and the connection can be completed when required. It is currently anticipated that wells SS-10 and SS-11 will be used as and when further volumes to the NNGI are required.

COMMODITY PRICES

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

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$/mcf	**2018**	2017	**2018**	2017
Average sales price				
Industrial sector	**8.44**	7.78	**8.26**	7.71
Power sector	**3.68**	3.63	**3.68**	3.60
Weighted average price	**4.31**	4.93	**5.17**	4.84

Industrial sector

The average Industrial sales price achieved during the year was $8.26/mcf, an increase of 7% from $7.71/mcf in 2017. The average Industrial price in the fourth quarter was $8.44/mcf (Q4 2017: $7.78/mcf), an increase of 8%. The increase in prices is due to the underlying increase in the price of heavy fuel oil against which most of the industrial customer contracts are priced.

Power sector

The average sales price to the Power sector was $3.68/mcf for the year (2017: $ 3.60 /mcf) and $3.68/mcf (Q4 2017: $3.63/mcf) for the quarter. The increase in price for the year and quarter is primarily due to the annual indexation in accordance with the PGSA and ARGA.

OPERATING REVENUE

The Company's operating revenue was $14.2 million in the quarter ended December 31, 2018 (Q4 2017: $11.8 million). The 20% increase for the quarter is a result of the increase in sales volumes and prices to industrial customers together with the decreased TPDC Profit Gas revenue entitlement. The 2% increase in gross field revenue to $20.9 million from $20.5 million for the quarter is a combination of the increase in the weighted average sales price and the recognition of all the TANESCO sales invoices for the quarter as opposed to only 90% recognized in Q4 2017. The Company's operating revenue for the year ended December 31, 2018 increased by 1% to $54.4 million from $53.7 million for the year ended December 31, 2017. The increase is primarily a result of the increase in gross field revenue associated with the inclusion of $4.2 million of TANESCO deferred revenue in Q1 2018. The increase in TPDC Profit Gas revenue entitlement for the year ended December 31, 2018 is a result of lower volumes and the depletion of the Cost Pool offset by the increase in gross field revenue for the same period.

Revenue presented on the Consolidated Statements of Comprehensive Income may be reconciled to the Company's operating revenue by adding the income tax adjustment of $0.7 million for the quarter and adding the income tax adjustment of $3.3 million for the year ended December 31, 2018. The Company is liable for income tax in Tanzania, but under the terms of the PSA TPDC's Profit Gas revenue 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%.

Reconciliation of Company operating revenue to revenue:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$'000	**2018**	2017	**2018**	2017
Company operating revenue	**14,165**	11,799	**54,434**	53,716
Current income tax adjustment	**(705)**	(1,191)	**3,332**	7,116
Revenue	**13,460**	10,608	**57,766**	60,832

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 ("Contract Expenses") up to a maximum of 75% of the net field revenue through Cost Gas revenue prior to the distribution of Profit Gas revenue. Any Contract Expenses not recovered in any period are carried forward for recovery out of future revenues (the "Cost Pool"). Once the Cost Pool 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 below 40 MMcfd. However, for Q3 2018 and Q4 2018 the Additional Gas volumes were above 40 MMcfd. As a consequence, the Company was entitled to a 40% share of Profit Gas revenue in Q3 2018 and Q4 2018 compared to a 35% share of Profit Gas revenue in Q1 2018 and Q2 2018. In 2017, the Company was entitled to a 35% share of Profit Gas revenue in Q4 2017 and Q2 2017 and to a 40% share of Profit Gas revenue in Q1 2017 and Q3 2017. See "Principal Terms of the Tanzanian PSA and Related Agreements."

The Company was allocated a total of 65% of the net field revenue in 2018 (2017: 72%). The decrease in allocation of the net field revenue is a result of the depletion of the Cost Pool during the latter half of 2017 following the recovery of the capital costs associated with the completion of offshore phase of the Development Program in 2016 which included workovers on wells 5, 7 and 9 and the drilling of well SS-12.

Analysis of gross and net field revenue

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$'000	**2018**	2017	**2018**	2017
Industrial sector	**10,077**	8,639	**39,095**	35,440
Power sector	**10,774**	11,870	**40,395**	35,916
Gross field revenue	**20,851**	20,509	**79,490**	71,356
TPDC share of revenue	**(6,686)**	(8,710)	**(25,056)**	(17,640)
Company operating revenue	**14,165**	11,799	**54,434**	53,716
Reconciliation to net field revenue:				
Gross field revenue	**20,851**	20,509	**79,490**	71,356
Tariff for processing and pipeline infrastructure [(1)]	**(2,347)**	(2,091)	**(8,509)**	(8,978)
Net field revenue	**18,504**	18,418	**70,981**	62,378
Allocation of net field revenue:				
Company Cost Gas revenue	**7,361**	4,724	**30,377**	34,091
Company Profit Gas revenue	**4,457**	4,984	**15,548**	10,647
Company share of net field revenue	**11,818**	9,708	**45,925**	44,738
TPDC Profit Gas entitlement	**6,686**	8,710	**25,056**	17,640
Net field revenue	**18,504**	18,418	**70,981**	62,378

[(1)] *Under the application of IFRS 15 Revenue, the revenue is shown gross, with the tariff for transportation and pipeline tariff being included in production and distribution expenses.*

Impact of IFRS 15

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$/mcf	**2018**	2017	**2018**	2017
Revenue prior to implementation of IFRS 15	**11,216**	8,528	**49,258**	51,854
Tariff for processing and pipeline infrastructure	**2,347**	2,091	**8,508**	8,978
Revenue	**13,563**	10,619	**57,766**	60,832

There is no impact on net income (loss) as a result of the implementation of IFRS 15.

TANESCO impact on revenue

The Company records 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. The percentage used to recognize TANESCO revenue will be reviewed as circumstances require. Commencing April 1, 2018 the Company has been recording 100% of deliveries to TANESCO as revenue. This is a result of TANESCO consistently paying in excess of amounts invoiced for deliveries.

Prior to April 1, 2018 cash received in excess of the revenue recorded for deliveries to TANESCO in any given period was recorded as deferred revenue. In periods when the deferred revenue balance was greater than the amounts invoiced to TANESCO for gas deliveries for the previous four quarters, any amount in excess of the previous four quarter average was recorded as current period revenue to the extent there had been unrecognized revenue resulting from the expected collectability approach. 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 trend of TANESCO paying in excess of gas delivered continued throughout 2018 and into 2019. Based on the consistent payments from TANESCO, the Company: (i) recognized all amounts invoiced in Q2 2018 through Q4 2018 for gas deliveries as revenue; (ii) in Q2 2018 recognized $8.1 million of previously recognized revenue as finance income (which represented excess cash received over invoiced amounts for gas deliveries which had not previously been applied against TANESCO long-term arrears; (iii) in Q4 2018 recognized $1.0 million (Q3 2018: $1.4 million, Q2 2018: $5.4 million) as finance income relating to the amounts collected during 2018 that were applied towards the long-term TANESCO arrears previously provided for. The revenue recorded for 2018 includes the release of $4.2 million of deferred revenue to gross field revenue in Q1 2018 and the reallocation of $2.6 million TPDC Profit share entitlement which resulted in an overall increase of $1.3 million in earnings for the year.

PRODUCTION, DISTRIBUTION AND TRANSPORTATION 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 $0.2 million (Q4 2017: $0.3 million) and $1.1 million for the year (2017: $1.2 million). Amounts allocated to Additional Gas for the quarter were $0.1 million (Q4 2017: $0.1 million) and $0.3 million for the year (2017: $0.4 million).

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.

The processing and transportation tariff charges for the quarter were $2.3 million (Q4 2017: $2.1 million) and $8.5 million for the year (2017: $9.0 million). The lower tariff expenses for the year are a result of the decrease in production volumes.

Distribution costs represent the direct cost of maintaining the ring main distribution pipeline and pressure reduction stations owned by the Company (security, insurance and personnel). Ring main distribution costs for the quarter were $0.7 million (Q4 2017: $0.7 million) and $2.8 million for the year (2017: $2.4 million). The production and distribution costs are detailed in the table below:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$'000	**2018**	2017	**2018**	2017
Share of well maintenance	**49**	121	**284**	392
Other field and operating costs	**197**	155	**836**	806
	246	276	**1,120**	1,198
Tariff for processing and pipeline infrastructure	**2,347**	2,091	**8,508**	8,978
Ring main distribution costs	**734**	655	**2,750**	2,431
Production, distribution and transportation expenses	**3,327**	3,022	**12,378**	12,607

OPERATING NETBACKS

The operating netback before general and administrative costs, overhead, tax and APT is detailed in the table below (see Non-GAAP measures):

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$/mcf	**2018**	2017	**2018**	2017
Gas price – Industrial	**8.44**	7.78	**8.26**	7.71
Gas price – Power [(1)]	**3.68**	3.63	**3.68**	3.60
Weighted average price for gas	**4.31**	4.93	**5.17**	4.84
TPDC share of revenue	**(1.62)**	(1.81)	**(1.56)**	(1.01)
Well maintenance and other operating costs	**(0.06)**	(0.08)	**(0.08)**	(0.08)
Tariff for processing and pipeline infrastructure	**(0.57)**	(0.59)	**(0.58)**	(0.59)
Ring main distribution costs	**(0.18)**	(0.19)	**(0.19)**	(0.16)
Operating netback	**1.88**	2.26	**2.76**	3.00

(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 (see Collectability of Receivables).*

The operating netback in the quarter decreased by 17% to $1.88/mcf (Q4 2017: $2.26/mcf) and decreased by 8% to $2.76/mcf for the year (2017: $3.00/mcf). The decrease in Q4 2018 is predominately due to the decrease in the weighted average gas price in the quarter to $4.31/mcf (Q4 2017: $4.93/mcf). The decrease for the year is primarily due to the increase in TPDC share of revenue to $1.56/mcf (2017: $1.01/mcf) which was partially offset by the increase in the weighted average price of gas to $5.17/mcf (2017: $4.84/mcf) as a result of a change in the sales mix. The increase in the weighted average price is the result of: (i) the relative increase of industrial sales to total sales with the overall level of industrial sales remaining relatively constant between periods; and (ii) the increase in the price paid by industrials due to the rise in the price of heavy fuel oil.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses are detailed in the table below:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$'000	**2018**	2017	**2018**	2017
Employee and related costs	**1,268**	2,712	**6,084**	7,147
Office costs	**1,585**	1,054	**5,230**	3,759
Marketing and business development costs	**202**	762	**427**	1,307
Reporting, regulatory and corporate	**280**	716	**1,086**	1,976
General and administrative expenses	**3,335**	5,244	**12,827**	14,189

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. General and administrative expenses averaged $1.1 million (Q4 2017: $1.7 million) per month during the quarter and $1.1 million (2017: $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	
$'000	**2018**	2017	**2018**	2017
Stock appreciation rights ("SARs")	**(362)**	904	**2,440**	2,271
Restricted stock units ("RSUs")	**(57)**	1,171	**2,203**	4,348
Stock-based compensation	**(419)**	2,075	**4,643**	6,619

As at December 31, 2018 a total of 645,000 SARs were outstanding compared to 2,485,000 SARs as at December 31, 2017. A total of 1,630,000 SARs with exercise prices ranging from CDN$2.30 to CDN$3.87 were exercised during the year resulting in a total cash payout of $5.4 million. A total of 210,000 SARs with an exercise prices ranging from CDN$2.30 to CDN$3.87 were forfeited during 2018. As at December 31, 2018 a total of 87,500 RSUs were outstanding compared to 1,147,621 RSUs as at December 31, 2017. A total of 1,060,121 RSUs were exercised during the year resulting in a total cash payout of $5.5 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 SARs and RSUs at the reporting date, the following assumptions have been made: a risk free rate of interest of 1.0%; stock volatility of 25.3% to 47.4%; 0% dividend yield; 5% forfeiture; and a closing price of CDN$5.05 per Class B share.

As at December 31, 2018 a total accrued liability of $1.6 million (2017: $7.9 million) has been recognized in relation to SARS and RSUs. The Company recognized credit of $0.4 million (Q4 2017: $2.1 million expense) for the quarter and an expense of $4.6 million for the year ended December 31, 2018 (2017: $6.6 million).

FINANCE INCOME AND EXPENSE

Finance income is detailed in the table below:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$'000	**2018**	2017	**2018**	2017
Interest income	**126**	155	**625**	366
Investment income	**423**	–	**1,084**	–
Reversal of provision for doubtful accounts	**2,560**	–	**17,427**	–
	3,109	155	**19,136**	366

In 2018 the Company has invested $66.8 million in short and long-term bonds. The investment in bonds are currently all short-term with maturity dates from March 2019 to December 2019 and a range of interest rates from 0.875% to 2.125%. The $1.1 million investment income for the year ended December 31, 2018 includes accrued interest of $0.6 million and amortization of the discount on the acquisition of the bonds $0.5 million. To date, the Company has received interest income of $0.7 million. The Company intents is to hold the bond investments to maturity; however, the bonds are highly liquid by their nature and may readily be liquidated into cash if necessary.

The reversal of the provision for doubtful accounts of $17.4 million during the year includes: (i) $8.1 million of excess cash receipts over invoiced deliveries from Q3 2017 to Q1 2018 previously recorded as deferred revenue; (ii) $7.8 million of excess cash receipts over invoiced gas deliveries since the end of Q1 2018; (iii) $1.2 million of operatorship receivables previously charged to Songas and fully provided for at the end of 2017; and (iv) $0.3 million previously provided against a refundable VAT balance relating to an in Italian entity, the VAT refund being received in Q4 2018 .

Finance expense is detailed in the table below:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$'000	**2018**	2017	**2018**	2017
Base interest expense	**1,591**	1,594	**6,249**	6,250
Participatory interest expense	**342**	1,031	**4,745**	3,809
Interest expense	**1,933**	2,625	**10,994**	10,059
Net foreign exchange loss (gain)	**87**	(64)	**695**	(184)
Provision for doubtful accounts	**–**	(90)	**–**	(90)
Indirect tax	**328**	253	**3,689**	3,046
	2,348	2,724	**15,378**	12,831

Base and participatory interest expense relate to the long-term loan with the International Finance Corporation ("IFC"). The amount of base interest expense during the quarter was $1.6 million (Q4 2017: $1.6 million) and $6.2 million for the year ended December 31, 2018 (2017: $6.3 million). The participatory interest expense during the quarter was $0.3 million (Q4 2017: $1.0 million) and $4.7 million for the year ended December 31, 2018 (2017: $3.8 million). The increase in the participatory interest expense is the result of an additional payment of $2.6 million associated with the sale of the 7.9% interest in PAEM (see sections on Long-Term Loan and Non-Controlling Interest).

Net foreign exchange gains and losses are the result of transactions in foreign currencies being 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. These foreign exchange losses and gains are recorded in finance expense.

The provision for doubtful accounts for the year ended December 31, 2017 of $0.1 million represents a receipt from an industrial debtor which had been previously provided against.

The indirect tax of $0.3 million for the quarter (Q4 2017: $0.3 million) and $3.7 million for the year ended December 31, 2018 (2017: $3.0 million) is for VAT associated with invoices to TANESCO for interest on late payments and invoices under the take or pay provisions within the PGSA. The invoiced amounts are not recognized in the consolidated financial statements due to not meeting the revenue recognition criteria with respect to assurance of collectability.

TANESCO

At December 31, 2018 the current receivable from TANESCO was $ nil (December 31, 2017: $ nil). During the year the amounts received from TANESCO continued to be in excess of the revenue recognized for gas sales to TANESCO. Commencing April 1, 2018 the Company has recorded 100% of deliveries as revenue and during 2018, $15.9 million of cumulative excess receipts over sales invoiced was allocated to the long-term arrears together with the associated reversal of the provision for doubtful accounts.

The long-term trade receivable at December 31, 2018 was $58.5 million with a provision of $58.5 million compared with $74.4 million (with a provision of $74.4 million) at December 31, 2017. Subsequent to December 31, 2019 the Company has invoiced TANESCO $15.6 million for 2019 gas deliveries and TANESCO has paid the Company $18.0 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:

	YEAR ENDED DECEMBER 31	
$'000	**2018**	2017
Total amounts invoiced to TANESCO	**121,393**	108,833
Unrecognized amounts for not meeting revenue recognition criteria [i]	**(62,895)**	(38,710)
Invoiced amounts reduced based on TANESCO's payment history for the previous three years	**–**	(4,172)
Provision for doubtful accounts	**(58,498)**	(74,361)
TANESCO deferred revenue balance per consolidated financial statements	**–**	(8,410)

[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. During the Q2 2018 the Company invoiced TANESCO for $16.6 million relating to take or pay arrangements under the PGSA for the year ending June 30, 2018 (year ended June 30, 2017: $13.4 million). These amounts have not been recognized in the financial statements, however, the VAT associated with the invoice of $2.5 million (Q2 2017: $2.0 million) has been written off to finance expense in Q2 2018.

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 revenue 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, 2018 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 $12.8 million (2017: $11.8 million). During the year there was a deferred tax charge of $1.0 million compared to a deferred tax recovery of $1.2 million in 2017. 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 revenue.

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 ("APT") 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 annually forecasting the total APT payable in the future as a proportion of the Company's share of forecast Profit Gas over the term of the PSA. The forecast takes into account the timing of future development capital spending.

The effective APT rate for the quarter of 19.7% (Q4 2017: 19.4%) has been applied to Company Profit Gas of $4.5 million (Q4 2017: $5.0 million), and an average effective rate of 19.4% (2017: 19.4%) has been applied to Company Profit Gas of $15.5 million (2017: $10.6 million) for the year ended December 31, 2018. Accordingly, $0.9 million (Q4 2017: $1.0 million) and $3.0 million (2017: $2.1 million) have been recorded for the quarter, and for the year ended December 31, 2018, respectively. The Company has yet to earn an annual cash return of 25% and as such, none of the accrued amount is currently payable.

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$'000	**2018**	2017	**2018**	2017
Additional Profits Tax	**877**	962	**3,014**	2,063

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, 2018 the estimated proved reserves remaining to be produced over the term of the PSA licence were 261 Bcf (2017: 307 Bcf). A depletion expense of $3.2 million for the quarter (Q4 2017: $2.0 million) and $9.5 million for the year (2017: $8.7 million) has been recorded in the accounts at an average depletion rate to $0.62/mcf (2017: $0.58/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

FINANCIAL INSTRUMENTS

On January 1, 2018, the Company adopted IFRS 9 - Financial instruments. 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. The Company does not use hedging contracts to mitigate risk.

The three principal classification categories under the new standard for financial instruments are: measured at amortized cost, fair value through other comprehensive income ("FVOCI") and fair value through profit and loss ("FVTPL"). The classification of financial instruments under IFRS 9 is generally based on the business model in which a financial instrument is managed and its contractual cash flow characteristics. The previous categories under IAS 39 of held to maturity, loans and receivables and available for sale have been removed.

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected loss" model. The new impairment model applies to financial instruments measured at amortized cost, and contract assets and debt investments measured at FVOCI. Under IFRS 9, credit losses will be recognized earlier than under IAS 39.

Cash and cash equivalents, accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities, and bank debt continue to be measured at amortized cost and are now classified as "amortized cost". There were no changes to the Company's classifications of its financial instrument assets and liabilities as FVTPL. None of the Company's financial instruments have been classified as FVOCI.

The Company did not formerly apply hedge accounting to its financial instruments and has not elected to apply hedge accounting to any of its financial instruments upon adoption of IFRS 9. There was no impact to the Company as a result of adopting the new standard.

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. Measurement in subsequent periods depends on the classification of the financial instrument as described below:

- Fair value through profit or loss: financial instruments under this classification include cash and cash equivalents and derivative assets and liabilities.
- Amortized cost: financial instruments under this classification include accounts receivable, investment in bonds, investments, accounts payable and accrued liabilities, dividends payable, tax payable, finance lease obligations, and long-term debt.

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.

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.

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 Q4 2018 the Company incurred $2.6 million (Q4 2017: $0.1 million) in capital expenditures and $5.8 million for the year ended December 31, 2018 (2017: $1.5 million). The capital expenditures in 2018 primarily relate to the completion of the SS-12 well flow line ($0.6 million) and the work on the refrigeration unit for the Songas Plant which is scheduled to be completed in Q2 2019.

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$'000	**2018**	2017	**2018**	2017
Geological and geophysical and well drilling	**–**	–	**–**	30
Pipelines and infrastructure	**2,561**	442	**5,744**	1,262
Other equipment	**67**	30	**99**	253
	2,628	472	**5,843**	1,545
Other [1]	**–**	–	**–**	7,352
	2,628	472	**5,843**	8,897

[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 $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.*

CASH FLOW SUMMARY

$'000	THREE MONTHS ENDED DECEMBER 31 2018	2017	YEAR ENDED DECEMBER 31 2018	2017
Operating activities				
Net income (loss)	**2,910**	(4,684)	**13,563**	(2,500)
Non-cash adjustments	**4,847**	4,836	**21,919**	19,332
Base interest paid	**1,591**	1,594	**6,249**	6,250
Participatory interest	**342**	1,031	**4,745**	3,809
Changes in non-cash working capital (1)	**(5,605)**	10,105	**(17,724)**	21,263
Net cash flows from operating activities	**4,085**	12,882	**28,752**	48,154
Net cash used in investing activities	**(2,471)**	(500)	**(5,051)**	(1,683)
Net cash from (used in) financing activities	**1,444**	(602)	**(81,665)**	(5,258)
Increase (decrease) in cash	**3,058**	11,780	**(57,964)**	41,213
Effect of change in foreign exchange on cash	**161**	54	**302**	214
Net increase (decrease) in cash	**3,219**	11,834	**(57,662)**	41,427

(1) *See Consolidated Statements of Cash Flows*

The Company's net cash flow from operating activities for the quarter ended December 31, 2018 decreased by 68% to $4.1 million (Q4 2017: $12.9 million) and decreased by 40% for the year ended December 31, 2018 to $28.8 million (2017: $48.2 million). The decrease in the quarter is primarily a result of the changes in non-cash working capital for the quarter, a decrease of $5.6 million (Q4 2017: $10.1 million increase). The decrease for the year is primarily a result of the exercise of SARs and RSUs during the year and changes in non-cash working capital primarily due to the increase in TPDC Profit Gas payable and deferred revenue. The increase in cash used in investing activities is the result of increased capital expenditures. The increase of cash used in financing activities for the year is the combined result of an investment in short-term bonds of $66.8 million, dividend payments of $17.9 million (including $1.0 million dividend paid to a non-controlling interest), and the payment of participatory interest of $6.1 million, which have been offset by the proceeds received on the sale of a non-controlling interest in a subsidiary of $15.4 million.

WORKING CAPITAL

Working capital as at December 31, 2018 was $84.2 million (December 31, 2017: $69.6 million) and is detailed in the table below:

		AS AT DECEMBER 31		
$'000		**2018**		2017
Cash		**64,660**		122,322
Investment in short term bonds		**66,837**		–
Trade and other receivables		**15,862**		12,273
Songas	2,489		2,378	
Industrial customers	9,107		6,915	
Songas gas plant operations	6,496		5,827	
Other receivables	1,937		2,521	
Provision for doubtful accounts	(4,167)		(5,368)	
Prepayments		**1,217**		866
		148,576		135,461
Trade and other payables		**64,394**		56,758
TPDC share of Profit Gas revenue (1)	40,260		33,422	
Songas	1,785		1,670	
Other trade payables	2,725		1,961	
Accrued liabilities	14,864		19,705	
Current portion of long-term loan	4,760		–	
Deferred revenue (2)		**–**		8,410
Tax (recovery) payable		**–**		718
		64,394		65,886
Working capital		**84,182**		69,575

(1) *The balance of $40.3 million payable to TPDC is the accrued liability for their share of Profit Gas revenue primarily related to unpaid gas deliveries to TANESCO, net of $0.3 million previously recorded as tax recoverable. The majority of the settlement of this liability is dependent on receipt of payment from TANESCO for arrears. A total of $4.6 million was paid to TPDC in February 2019.*

(2) *As at December 31, 2018 TANESCO deferred revenue is $ nil (December 31, 2017: $8.4 million). Deferred revenue at December 31, 2017 was a result of the cumulative cash collected from TANESCO being in excess of the invoiced amounts recognized as revenue. Commencing April 1, 2018 all invoices for deliveries have been recorded as revenue and any amounts collected in excess of deliveries are recorded as a recovery of arrears. During 2018 the cumulative excess receipts over recognized revenue of $15.9 million have been offset against the long term TANESCO receivable as a result there is no deferred revenue in working capital at December 31, 2018. There is no current receivable from TANESCO at December 31, 2018 (December 31, 2017: $ nil). The long-term TANESCO receivable as at December 31, 2018, including unrecorded invoices not meeting revenue recognition criteria, was $121.4 million. The Company is actively pursuing the collection of all the receivables that have been charged to TANESCO.*

Working capital as at December 31, 2018 increased by 21% over December 31, 2017. The successful collection of TANESCO receivables has increased current assets by $13.0 million. This has been offset by an increase in trade and other payables of $0.7 million and the release of $8.4 million deferred revenue.

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 and investment in bonds is currently held outside of Tanzania.
- The Company expects to have sufficient cash flows from operating activities and working capital to cover budgeted debt and interest payments ($13.0 million) and capital expenditures ($3.4 million) for 2019. The Company does not expect to incur any losses from debtors in 2019.
- Of the $9.1 million receivable relating to industrial customers $7.7 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 IFC, a member of the World Bank Group, for $60 million. The Loan was fully drawn in 2016.

The term of the Loan is ten 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 $5 million starting April 15, 2022 and one final payment of $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 (taken on December 14, 2015), 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 was initially guaranteed by the Company to a maximum of $30 million. The initial guarantee may only be called upon by the 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. Pursuant to the sale of the non-controlling interest in PAEM, the Company agreed with the IFC to reduce the outstanding amount of the loan by the percentage interest sold in PAEM of 7.9% ($4.8 million) on the fourth anniversary of the first drawdown. The Company has provided an additional guarantee to the IFC that if PAET is unable to pay down the loan on or before December 14, 2019, the Company will make the payment. This guarantee is in addition to the Company's initial guarantee.

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 amount of base interest during the quarter was $1.6 million (Q4 2017: $1.6 million) and $6.2 million for the year (2017: $6.3 million). To date all interest incurred has been paid when due.

In addition, the Loan included 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 of whether the Loan is repaid prior to its contractual maturity date. The participatory interest charged during the fourth quarter was $0.3 million (Q4 2017: $1.0 million) and $4.7 million for the year (2017: $3.8 million). The 2018 charge includes an additional payment of $2.6 million (2017: $ nil) associated with the sale of the 7.9% interest in PAEM in January 2018 in accordance with the terms of the Loan. As a result of the additional payment, the annual variable participatory interest is reduced from 7% to 6.4%. At December 31, 2018 the participatory interest included in accrued liabilities is $2.6 million (December 31, 2017: $3.8 million).

Dividends and distributions from PAET to the Company are restricted at any time that any amounts due for interest, principal or participating interest are outstanding under the Loan.

OUTSTANDING SHARES

There were 35,256,432 shares outstanding as at December 31, 2018 as detailed in the table below. 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.

	AS AT DECEMBER 31	
Number of shares ('000)	**2018**	2017
Shares outstanding		
Class A shares	**1,750**	1,750
Class B shares	**33,506**	33,506
Class A and Class B shares outstanding	**35,256**	35,256
Weighted average		
Class A and Class B shares	**35,256**	34,858
Convertible securities		
Options	**–**	–
Weighted average diluted Class A and Class B shares	**35,256**	34,858

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 fourth quarter costs of $ nil (Q4 2017: $0.6 million) and $0.3 million for the year (2017: $0.9 million) were incurred by this firm for services provided. As at December 31, 2018 the Company has a total of $0.04 million (December 31, 2017: $0.5 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 ($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 (191 Bcf as at December 31, 2018). 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.

Re-Rating Agreement

In 2011 the Company signed the Re-Rating Agreement which evidenced an increase to the gas processing capacity of the Songas Plant to a maximum of 110 MMcfd (the pipeline and delivery 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 $0.30/mcf for sales between 70 MMcfd and 90 MMcfd and $0.40/mcf for volumes above 90 MMcfd by issuing credit notes to TANESCO. This was in addition to the tariff of $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.

There remains a disagreement as to the current status of the Re-Rating Agreement, however, the processing capacity at the Songas Plant remains unaltered and is fully available for utilization by the Company. This capacity is in addition to the capacity available within the NNGI.

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). TANESCO requested a change to the PGSA Maximum Daily Quantity which PAET and TPDC approved effective January 29, 2018. The seller is now 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 $2.98/mcf increased to $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. On December 22, 2018 a side letter amendment to the PGSA was agreed with TPDC to allow PGSA volumes up to a maximum monthly average volume of 35 MMscf/d to temporarily flow through the NNGI. It is intended that this temporary arrangement is to be replaced by the initialed GSA. The extra and excess charges to TANESCO are not applicable for volumes supplied pursuant to the side letter agreement.

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 $0.4 million. The agreement in Winchester expires on September 25, 2022 at an annual rental of $0.2 million per annum. The costs of these leases are recognized in the general and administrative expenses. Subsequent to year-end the Company leased offices in London for a twelve-month period for $0.2 million per annum. The intent is to sub-let the office in Winchester for the duration of the rental agreement but until a sub-let is finalized, the Company continues to make the quarterly rental payments.

Capital Commitments

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. The Company began work on the onshore component of Phase A of the Development Program in 2018 that includes installation of a refrigeration unit at the Songas Plant with an estimated cost of $8.5 million and well workovers with an estimated cost of $13.6 million. A total of $4.2 million was incurred on the refrigeration project in 2018 which is scheduled for completion in Q2 2019. A portion of the well workover costs are for wells SS-3 and SS-4 and assuming that Songas, the owner of the wells, funds the costs for these workovers the estimated workover cost to the Company will be $5.1 million. All planned capital expenditures can be funded out of the Company's existing working capital and cash flow.

At the date of this report, the Company has no significant outstanding contractual commitments.

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 of Tanzania. 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 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 (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. 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 $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. Subsequent to December 31, 2018 discussions on the disputed amounts resumed with TPDC based on a report published by the attorney general. At the time of writing this report no independent 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. Presently there are no formal disputes with TPDC regarding cost recovery.

Taxation

		TAX DISPUTE	DISPUTED AMOUNT $' 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.	1.0	0.7	1.7 (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).	29.0	13.6	42.6 (3)
VAT	2008-10	Output VAT on imported services and SSI Operatorship services.	2.7	2.8	5.5 (4)
			33.0	17.1	50.1

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 $50.1 million (December 31, 2017: $47.2 million).

(1) 2015 ($0.3 million): 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 the TRAB decision which ruled in favour of the 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 the CAT hearing date to be set;

(2) (a) 2005-2009 ($1.6 million): In 2016 TRA filed an application for review of the 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 for their application, under the certificate of urgency, for the CAT to review its judgment. During Q1 2018 the CAT ruled in favour of PAET's preliminary objection. In Q4 2018 TRA applied to the CAT to file an application for review out of time but consequently withdrew its application: at the time the Company was preparing to file a preliminary objection against the application. It is not clear whether the TRA will seek to re-file their application;

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

(c) 2012-2015 ($0.0 million): TRA has assessed the Company for withholding tax for services not in the Company's records. Management has objected the assessment and is awaiting TRA response;

(3) (a) 2008 ($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 $1.8 million (with tax impact of $0.6 million). PAET has objected to the assessment for being time-barred, incorrect and arbitrary;

(b) 2009 ($2.6 million): In 2015 TRAB ruled against PAET with respect to timing of deductibility of capital expenditures and other expenses ($1.8 million). In Q2 2017 PAET lost an appeal at TRAT and in July 2018 lost an appeal at CAT. The Company has filed an application for review of the judgment and is awaiting CAT hearing date. In July 2017 TRA sent PAET an amended assessment claiming additional taxes, interest and penalties ($0.8 million). PAET has objected to the assessment for being time-barred and arbitrary and is awaiting a TRA response;

(c) 2010 ($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. The Company is awaiting for a date of hearing at TRAB;

(d) 2011 ($1.9 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 ($1.7 million). The Company is awaiting for a date of hearing at TRAB. 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 ($0.2 million) raised for the year;

(e) 2012 ($15.5 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. Aggrieved by the TRAT decision, the Company filed a Notice of Appeal with the Court of Appeal and is awaiting a hearing date;

(f) *2013 ($8.2 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 ($1.9 million) which disallowed certain operating costs included in the tax returns and tax on repatriated income ($6.3 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 now is awaiting for a date of hearing at TRAB;*

(g) *2014 ($11.0 million): In 2016 TRA issued an assessment of $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 now is awaiting for a hearing date at TRAB. TRA issued two additional assessments for the year for corporation tax of $4.7 million and tax on repatriated income $3.0 million. PAET has objected the assessments and is awaiting TRA response;*

(h) *2015 ($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 ($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. The appeal was heard on November 1-2, 2018 and the parties are now awaiting for the TRAB judgment;*

(b) *2012-2014 ($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.*

In 2016 TRA introduced significant changes in relation to the income tax treatment of the extractive sector with new separate chapters in Part V of the Income Tax Act 2004 ("ITA, 2004") for mining and for petroleum to be effective commencing in 2018. Subsequent to this, further changes were made by the Written Laws (Miscellaneous Amendments) Act, 2017 ("WLMAA, 2017"), and in particular section 36(a)(ii) of the WLMAA, 2017. The WLMAA, 2017 amended section 65M and 65N of the ITA 2004 to exclude cost oil/cost gas from inclusion in both income and expenditure. The Company is still evaluating the tax effects of the changes as there are a number of uncertainties and ambiguities as to the interpretation and application of certain provisions of the WLMAA, 2017. In the absence of guidance on these matters and until the 2018 tax returns are finalized which the Company expects to occur in June 2019, the Company expects to use what it believes are reasonable interpretations and assumptions in applying the WLMAA, 2017 for purposes of determining its tax liabilities and results of operations, which may change as it receives additional clarification and implementation guidance.

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, 2019 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 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 and IFRIC 4-Determining whether an Arrangement contains a Lease and related interpretations. IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019. The standard is required to be adopted either retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect of IFRS as an adjustment to opening retained earnings and applies the standard prospectively. On January 1, 2019, the Company will adopt IFRS 16 and plans to use the modified retrospective approach.

On adoption, the Company currently intends on applying the following practical expedients permitted under the standard. Some expedients are available on a lease-by-lease basis, while others are applicable by class of underlying asset.

i) Any leases with terms ending within 12 months of January 1, 2019 will be recognized as short-term leases and included in the short-term lease disclosure. These leases will not be recognized on the statement of financial position on initial adoption.

ii) The Company will exclude initial direct costs from the measurement of the right-of-use asset on transition for any leases with associated initial direct costs.

iii) Short-term leases and leases of low value assets that have been identified at January 1, 2019, will not be recognized on the statement of financial position. Payments for these leases will be disclosed in the notes to the financial statements.

The Company has completed an initial assessment but not yet finalized the potential impact on its consolidated financial statements. The full impact of applying IFRS 16 on the financial statements in the period of initial application will depend on multiple factors and conditions, including but not limited to, the Company's borrowing rate at January 1, 2019, the composition of the Company's lease portfolio at that date and the Company's latest assessment of whether it will exercise any lease renewal or termination options.

Thus far, the most significant impact identified is that the Company will now recognize new assets and liabilities on its Statement of Financial Position for its real estate. In addition, the nature of the expenses related to those leases will change. Straight-line operating lease expense will be replaced with a depreciation charge for right-of-use assets and interest expense on lease liabilities.

The Company continues to review all existing contracts in detail. The full extent of the impact has not yet been determined. The Company continues to remain focused on developing and implementing changes to policies, internal controls, information systems and business and accounting processes.

New accounting policies

IFRS 9

On January 1, 2018, the Company adopted IFRS 9 - Financial instruments. 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.

The three principal classification categories under the new standard for financial instruments are: measured at amortized cost, fair value through other comprehensive income ("FVOCI") and fair value through profit and loss ("FVTPL"). The classification of financial instruments under IFRS 9 is generally based on the business model in which a financial instrument is managed and its contractual cash flow characteristics. The previous categories under IAS 39 of held to maturity, loans and receivables and available for sale have been removed.

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected loss" model. The new impairment model applies to financial instruments measured at amortized cost, and contract assets and debt investments measured at FVOCI. Under IFRS 9, credit losses will be recognized earlier than under IAS 39.

Cash and cash equivalents, accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities, and bank debt continue to be measured at amortized cost and are now classified as "amortized cost". There were no changes to the Company's classifications of its financial instrument assets and liabilities as FVTPL. None of the Company's financial instruments have been classified as FVOCI.

The Company did not formerly apply hedge accounting to its financial instruments and has not elected to apply hedge accounting to any of its financial instruments upon adoption of IFRS 9. There was no impact to the Company as a result of adopting the new standard.

IFRS 15

On January 1, 2018 the Company adopted IFRS 15 – Revenue from Contracts with Customers, which 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. The Company has adopted 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 using the IFRS 15 five step model there were no material changes to net income, the timing of revenue recognized or to opening retained earnings as at January 1, 2018. The Company has expanded disclosures in the notes to its consolidated financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue with the Songas processing and transportation tariff being recorded in production, distribution and transportation costs as opposed to a direct deduction from revenue.

DIVIDEND

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; the dividend was paid on February 7, 2018.

NON-CONTROLLING INTEREST

On January 16, 2018 the Company sold 7.9 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 $15.7 million cash (net of closing adjustments) and $4.0 million of Swala convertible preference shares pursuant to a share purchase agreement. The preference shares were issued to the Company on June 18, 2018 and entitle the Company to a 10% per annum distribution payable 15 days after each quarter end commencing from the closing date, January 16, 2018. Payment of the quarterly distributions is at the discretion of Swala based on funds available, however, the liability accrues if any amount is unpaid when due. If any distributable amount remains unpaid at December 31, 2021, the Company may demand settlement and Swala is obligated to comply by transferring and returning shares of PAEM sold to Swala; the aggregate value of these shares will equal the amount of the outstanding distributions. As at December 31, 2018 the Company has not received any distributions or recorded any amount receivable related to the preference shares.

Swala is obligated to redeem 20% of the preference shares for cash annually starting December 31, 2021 until all shares are redeemed. If at any time Swala does not redeem in cash the required number of shares, Swala shall be obligated to redeem the preferred shares by transferring and returning shares of PAEM sold to Swala; the aggregate value of these shares will equal the amount of any outstanding redemption.

Following the issue of the preference shares a further price adjustment of $0.3 million was recorded, reducing the total cash consideration for tranche one of the transaction to $15.4 million.

The share purchase agreement provided Swala with the right to acquire up to a maximum of 40% of the outstanding Class A common shares of PAEM based on the same terms and conditions. Subsequent to December 31, 2018 the Company terminated this right.

A reconciliation of the non-controlling interest is detailed below:

	AS AT DECEMBER 31	
(000)	**2018**	2017
Balance, beginning of period	–	–
Recorded at the date of disposition	178	–
Share of post-disposition income	293	–
Balance, end of period	471	–

SUBSEQUENT EVENTS

On January 22, 2019 the Company declared a dividend of CDN$0.05 per share on each of its Class A voting and Class B subordinate voting shares to holders of record as of March 31, 2019 and payable on or about April 30, 2019.

SUMMARY QUARTERLY RESULTS

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

Figures in $'000 except where otherwise stated	**2018**				2017			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial								
Revenue	**13,460**	15,124	14,959	14,223	10,619	15,287	16,810	18,216
Net income (loss) attributable to shareholders	**2,751**	2,637	12,493	(4,611)	(4,684)	(34)	(622)	2,840
Earnings (loss) per share – basic and diluted *($)*	**0.09**	0.07	0.35	(0.13)	(0.13)	(0.00)	(0.02)	0.08
Adjusted funds flow from operations [(1)]	**6,398**	5,130	4,752	2,975	62	4,361	5,380	6,939
Adjusted funds flow from operations per share – basic and diluted *($)* [(1)]	**0.18**	0.15	0.14	0.08	0.00	0.12	0.16	0.20
Net cash flows from operating activities	**4,085**	10,483	12,657	1,527	12,882	14,447	12,038	8,787
Net cash flows per share – basic and diluted *($)*	**0.12**	0.30	0.36	0.04	0.37	0.41	0.35	0.25
Operating netback *($/mcf)* [(1)]	**1.88**	2.38	3.17	2.23	2.26	2.94	3.44	3.34
Working capital	**84,182**	79,955	72,129	65,201	69,575	71,129	73,854	68,112
Long-term loan	**53,900**	58,603	58,596	58,557	58,518	58,501	58,468	58,399
Shareholders' equity	**93,702**	91,336	89,018	76,636	78,731	82,426	82,407	82,982
Capital expenditures								
Geological and geophysical and well drilling	**–**	–	–	–	–	–	3	27
Pipeline and infrastructure	**2,561**	1,349	1,042	792	442	477	250	93
Other equipment	**67**	5	–	27	30	126	97	–
Other	**–**	–	–	–	–	–	–	7,352
Total	**2,628**	1,354	1,042	819	472	603	350	7,472
Operating								
Additional Gas sold *(MMcf)*								
– industrial	**1,194**	994	1,294	1,251	1,110	1,285	1,158	1,041
– power	**2,929**	3,022	1,774	2,114	2,428	2,867	2,437	2,873
Total	**4,123**	4,016	3,068	3,365	3,538	4,152	3,595	3,914
Additional Gas sold *(MMcfd)*								
– industrial	**13.0**	10.8	14.2	13.9	12.1	14.0	12.7	11.6
– power	**31.8**	32.8	19.5	23.5	26.4	31.1	26.8	31.9
Total	**44.8**	43.6	33.7	37.4	38.5	45.1	39.5	43.5
Average price per mcf *($)*								
– industrial	**8.44**	9.23	7.80	7.79	7.78	7.65	7.69	7.75
– power	**3.68**	3.78	3.62	3.60	3.63	3.63	3.57	3.57
Weighted Average price per mcf ($)	**4.31**	5.12	5.39	5.16	4.93	4.87	4.90	4.68

[(1)] See non-GAAP measures. Certain comparative period amounts for adjusted funds flow from operations have been reclassified to conform with the current period presentation.

PRIOR EIGHT QUARTERS

The amount of revenue recorded from Q1 2017 to Q1 2018 has been impacted by the Company recording in revenue a percentage of gas delivered to TANESCO. The amount recorded in revenue was based on the expected amount to be collected due to the poor payment history during the previous three years. Commencing April 1, 2018 the Company has been recording 100% of gas deliveries to TANESCO in revenue as a result of the improved TANESCO payment history during the previous 18 months. The above resulted in a net revenue reduction of $1.9 million in Q1 2017, a reduction of $0.8 million in Q2 2017, a net revenue increase of $1.8 million in Q3 2017, a net revenue increase of $1.0 million in Q4 2017 and a net revenue increase of $1.6 million in Q1 2018 (see "Company Operating Revenue").

In addition, the decrease in revenue from Q1 2017 to Q2 2017 is a result of reductions in the volume of gas sold to the industrial sector, primarily a result 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. The increase in revenue from Q4 2017 to Q1, Q2, and Q3 2018 was also impacted by the reversal of TANESCO deferred revenue to income during Q1, Q2, and Q3 2018 as a result of the improved TANESCO payment history.

Significant factors affecting net income attributable to shareholders in addition to changes in revenue were:

- The increase in Q2 2018 is a result of the reversal of the provision of doubtful accounts for TANESCO resulting in an increase in finance income of $13.4 million. The $2.6 million net income attributable to shareholders in Q3 2018 is a result of selling 43.6 MMcfd of Additional Gas, the first time the sales volumes have been over 40 MMcfd since Q3 2017, together with the reversal of the provision of doubtful accounts for TANESCO resulting in an increase in finance income of $1.4 million. The increase in Q4 2018 to $2.9 million is primarily due to the increase in revenue.
- The Company recorded an interest expense of $2.3 million in Q1 2017 and Q2 2017, $2.9 million in Q3 2017, $2.6 million in Q4 2017 and $4.7 million in Q1 2018, $2.1 million in Q2 2018, $2.3 million in Q3 2018, and $1.9 million in Q4 2018. The increase for Q1 2018 primarily relates to the participatory interest payable as a result of the sale of a non-controlling interest in PAEM in accordance with the terms of the IFC loan.
- Changes in stock based compensation due to fluctuations in the Company share price and issuance of new RSUs:
  - Q1 2017: Charge of $0.8 million predominately a result 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 $1.6 million predominately the result of the issuance of 1,143,255 RSUs. The share price closed at CDN$4.01.
  - Q3 2017: Charge of $2.1 million, share price closed at CDN$4.60.
  - Q4 2017: Charge of $2.1 million, share price closed at CDN$5.00.
  - Q1 2018: Charge of $4.6 million as a result of the exercise of both stock appreciation rights and restrictive stock units together with the increase in the closing share price at CDN$5.50.
  - Q2 2018: Charge of $0.4 million, share price closed at CDN$5.28.
  - Q3 2018: No significant charge in the quarter, share price closed at CDN$5.69. Share price increase was offset by the forfeiture of 100,000 SARs.
  - Q4 2018: Credit of $0.4 million as a consequence of the decline in the share price to CDN$5.05.

Differences in adjusted funds flow from operations for the last eight quarters were primarily a result of changes in revenue during the periods.

The decrease in adjusted funds flow from operations from Q1 2017 to Q2 2017 is a result 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 decrease from Q2 2017 to Q3 2017 is a result 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 from Q3 2017 to Q4 2017 is a combination of the fall in revenue, the increase in stock based compensation costs offset by a lower recovery of deferred taxation in the period. The increase from Q4 2017 to Q1 2018 was due to a combination of the increase associated with non-cash movement in stock based compensation offset by the increase in participatory interest payment to the IFC as a result of the sale of a non-controlling interest in PAEM. The increase from Q1 2018 to Q2 2018 is primarily a due to the continuing consistent payments from TANESCO resulting in a combination of recording 100% of TANESCO deliveries as revenue in Q2 together with recording the TANESCO deferred revenue balance as revenue for the period. The increase was partially offset by the increase in TPDC profit share. The increase from Q3 to Q4 2018 is predominately related to the increase in interest income and the reduction in the level of provision against the Songas operatorship.

Changes in net cash flows from operating activities between quarters were primarily a result of the timing and amount of payments received from TANESCO plus the factors noted above impacting net income and adjusted funds flow from operations. There was a general increase in cash flow from operating activities from Q1 2017 to Q4 2017 as TANESCO payments became regular and were normally in excess of gas deliveries. A large decrease occurred in Q1 2018, primarily due to the large stock based compensation paid in the quarter and the additional participating interest expense. The results for Q2 2018 were again consistent with the quarterly results in 2017 with lower sales being offset by an increase in collections from TANESCO. Decreases in Q3 2018 and Q4 2018 are a combination of changes in non-cash working capital following a payment of TPDC Profit Gas entitlement during the quarter along with the marginal decrease in revenue offset by savings in general administrative expenses.

The level of working capital between Q1 2017 and Q3 2017 remained fairly consistent at an average of $71.0 million. The fall in working capital to $69.6 million in Q4 2017 from $71.1 million in Q3 2017 is the result of the increased liabilities associated with the IFC loan and TPDC Profit Gas entitlement, offsetting the increased collections from TANESCO. The decrease in working capital between Q4 2017 and Q1 2018 from $69.6 million to $65.2 million is primarily due to the increase in stock-based compensation payments between periods. The increase in working capital between Q1 2018 and Q2 2018 is a result of the improved collections from TANESCO resulting in zero deferred revenue being carried in current liabilities. The increase in working capital between Q2 2018 to Q4 2018 is a result of the continued collection of TANESCO long-term arrears and the reduction in the level of long-term bonds from $7.2 million in Q2 2018 to $3.8 million in Q3 2018 and to $ nil in Q4 2018.

Capital expenditure for the last four quarters amounted to $5.8 million compared to $1.5 million from Q1 2017 to Q4 2017 excluding the transfer of the Songas share of workover costs incurred in 2015 to property, plant and equipment in Q1 2017. The capital expenditures in 2018 primarily relate to the completion of the SS-12 well flow line and the work on the refrigeration project on Songo Songo Island.

The level of Industrial sales volumes in the four quarters ending Q4 2018 averaged of 1,183 MMcf (four quarters ending Q4 2017: 1,149 MMcf) with total Industrial sales volumes for the four quarters ending Q4 2018 increasing to 4,733 MMcf (13.0 MMcfd) compared to 4,594 MMcf (12.6 MMcfd) in the four quarters ending Q4 2017. The increase is a result of reduced maintenance time at a cement plant in the first half of 2018 compared to the first half of 2017 and additional consumption by customers throughout 2018.

The level of Power sales volumes decreased by 7% in the four quarters ending Q4 2018 to an average of 2,460 MMcf (four quarters ending Q4 2017: 2,651 MMcf) with total Power sector sales volumes for the four quarters ending Q4 2018 decreasing to 9,839 MMcf (26.9 MMcfd) compared to 10,605 MMcf (29.1 MMcfd) in the four quarters ending Q4 2017. The decline is the result of lower offtakes by TANESCO.

SELECTED FINANCIAL INFORMATION

Selected annual financial information derived from the audited consolidated financial statements for the years ended December 31, 2018, 2017 and 2016 is set out below:

Figures in $'000 except per share amount	**2018**	2017	2016
Revenue	**57,766**	60,832	75,942
Net cash flows from operating activities	**28,752**	48,154	19,968
Adjusted funds flow from operations [(1)]	**19,255**	16,742	31,855
Net income (loss)	**13,270**	(2,500)	2,164
Earnings (loss) *($ per share)*:			
Basic and diluted	**0.38**	(0.07)	0.06
Cash dividends declared on all Class A and Class B shares *($ per share)*	**0.60**	–	–
Cash and cash equivalents	**64,660**	122,322	80,895
Investment in short term bonds	**66,873**	–	–
Total assets	**262,441**	249,549	221,130
Total non-current liabilities	**104,345**	104,932	103.912

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

Revenue decreased by 5% to $57.8 million in 2018 (2017: $60.8). The decrease in revenue for the year is primarily due to lower power sales volumes, higher TPDC Profit Gas entitlement and a lower current income tax adjustment. The 20% decrease of revenue to $60.8 million in 2017 (2016: $75.9 million) was primarily a consequence of recording revenue based on the expected collectability approach, a 7% decrease 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 cost pools.

The net cash flows from operating activities decrease of 40% to $28.8 million (2017: $48.2 million) is primarily a result of the exercise of Stock Appreciation Rights and Restrictive Stock Units in Q1 2018 together with decrease in the cash inflow associated with changes in non-cash working capital compared to the year ended December 31, 2017. The cash inflow associated with non-cash working capital for the year ended December 31, 2017 is the consequence of the increased trade and other creditors in relation to TPDC payable and deferred revenue. The increase in net cash flows from operating activities in 2017 of 141% to $48.2 million (2016: $20.0 million) was primarily the result of increased collections from TANESCO.

The Company's adjusted funds flow from operations for the year ended December 31, 2018 increased by $2.6 million to $19.3 million (2017: $16.7 million). The increase between years is primarily a result of reduced general and administration expenses ($1.2 million) and an increase in interest income on bonds ($1.3 million). The decrease in revenue between years of $3.1 million was offset by the decrease in current corporate income tax expense of $3.3 million.

The increase in net income in 2018 to $13.3 million (2017: $2.5 million loss) is primarily the result of the reversal of the provision for doubtful accounts related to the collection of TANESCO arrears previously provided for. The net loss of $2.5 million in 2017 (2016: $2.2 million net income) was a result of a decrease in revenue and an increase in stock based compensation and interest payments to the IFC being offset by lower TANESCO doubtful account provisions.

Total assets increased in 2018 by 5% to $262.3 million (2017: $249.5 million) and by 13% in 2017 (2016: $221.1 million). The increase in both years was primarily the result of increased collections from TANESCO increasing cash and investment balances.

Total non-current liabilities did not change significantly between the years. The decrease of $0.6 million in 2018 compared to 2017 was primarily due to the decrease in the long-term loan being partially offset by the increase in Additional Profits Tax.

BUSINESS RISKS

Financing

The Company has sufficient funds to meet all current commitments and obligations. The Company is currently considering additional capital expenditures in Tanzania and investing into new projects which could require 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 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.

Prior to 2017 TANESCO payments had been inconsistent and resulted in the Company recording provisions for doubtful accounts for amounts outstanding from TANESCO for more than 60 days. Commencing the last quarter of 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.

The percentage used to recognize TANESCO revenue is reviewed on at least a semi-annual basis, more frequently if circumstances require, and if there is a significant difference between the amounts of revenue recorded and amounts received; the percentage used to record revenue as well as any existing receivable or deferred revenue balance is revised accordingly. The percentage was increased effective October 1, 2017, January 1, 2018 and April 1, 2018 to reflect the most recent three-year payment history for TANESCO compared to amounts invoiced for deliveries. For the past three quarters the Company recorded 100% of TANESCO deliveries as revenue as receipts from TANESCO continue to be in excess of invoices for gas deliveries.

As at December 31, 2018 the current receivable from TANESCO was $ nil (December 31, 2017: $ nil). The long-term trade receivable at December 31, 2018 was $58.5 million (with a provision of $58.5 million) (December 31, 2017: $74.4 million with a provision of $74.4 million). Subsequent to December 31, 2018, the Company has invoiced TANESCO $15.6 million for 2019 gas deliveries and TANESCO has paid the Company $18.0 million.

As at December 31, 2018 Songas owed the Company $9.0 million (December 31, 2017: $8.2 million) while the Company owed Songas $2.2 million (December 31, 2017: $2.0 million). The amounts due to the Company are mainly for sales of gas of $2.5 million (December 31, 2017: $2.4 million) and for the operation of the gas plant of $6.5 million (December 31, 2017: $5.8 million) against which the Company has made a provision for doubtful accounts of $3.7 million (December 31, 2017: $4.9 million). The amounts due to Songas primarily relate to pipeline tariff charges of $1.8 million (December 31, 2017: $1.7 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 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 decrease in working capital (defined as current assets less current liabilities) of $0.2 million to $84.0 million and a decrease in the income before tax to $22.0 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, 2018

$'millions	**Canadian dollars**	**Tanzanian shillings**	**Euros**	**Other currencies**	**Total**
Cash	0.1	3.7	0.5	0.8	5.1
Trade and other receivables	–	3.2	0.4	0.2	3.8
Trade and other payables	(1.6)	(9.1)	–	(0.2)	(10.9)
	(1.5)	(2.2)	0.9	0.8	(2.0)

Foreign Operations

The Company's operations and related assets are located in Tanzania which may be considered to be politically and/or economically unstable. Exploration or development activities in Tanzania 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 99 out of 180 on the 2018 Transparency International Corruption Index (2017: 103 out of 180). 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 MoE). 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.

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 $1.2 billion NNGI 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 has come to a temporary agreement with TPDC to sell gas through the NNGI and is currently negotiating a longer term agreement 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, the 12-inch subsea and the 16-inch surface pipeline systems 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. This risk is mitigated to a significant extent as the completion of the NNGI at Songo Songo Island, provides a second option to deliver and sell additional Gas.

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 delivery pressure requirements). There remains a disagreement as to the current status of the Re-Rating Agreement and 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 signing of AGP2 by PAET, Songas and TPDC with approval of the MoE 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. 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. Management does not foresee a material risk with the conduct of the Company's business with an unsigned ARGA 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 NNGI. 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.

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 permanently through the NNGI, 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.

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

Shaymar Limited is the registered holder of approximately 20.7% of the equity (20.7% fully diluted) and controls 59.2% of the total votes of the Company. The shares are held in a trust that is independently managed. The beneficiaries of the trust include the children of W. David Lyons, former Chair and CEO of the Company. Mr. Lyons passed away in August 2018 and had previously been disclosed as controlling these shares. The Company has been advised by the trust that there is no current intention to sell or otherwise deal with the shares.

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.

- Adjusted funds flow from operations represents net cash flows from operating activities less interest expense and before changes in non-cash working capital. Management uses this is a performance measure that represents the company's ability to generate sufficient cash flow to fund capital expenditures and/or service debt.

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
$'000	**2018**	2017	**2018**	2017
Net cash flows from operating activities	4,085	12,882	28,752	48,154
Base interest expense	(1,591)	(1,594)	(6,249)	(6,250)
Participatory interest expense	(342)	(1,031)	(4,745)	(3,809)
Finance income re TANESCO arrears and VAT recovered	(1,359)	(90)	(16,227)	(90)
Changes in non-cash working capital	5,605	(10,105)	17,724	(21,263)
Adjusted funds flow from operations	6,398	62	19,255	16,742

The Company's adjusted funds flow from operations for the quarter ended December 31, 2018 was $6.4 million (Q4 2017: $0.1 million). The increase in adjusted funds flow from Q4 2017 to Q4 2018 is a combination of an increase in gas volume deliveries and the corresponding increase in revenue, the savings in general and administrative expenses and an increase in interest income from bonds. The Company's adjusted funds flow from operations for the year ended December 31, 2018 increased by $2.6 million to $19.3 million (2017: $16.7 million). The increase between years is primarily a result of reduced general and administration expenses ($1.2 million) and an increase in interest income on bonds ($1.3 million). The decrease in revenue between years of $3.1 million was offset by the decrease in current corporate income tax expense of $3.3 million.

- 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.
- Adjusted funds flow from operations per share is calculated on the basis of the adjusted 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.

CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The following are the critical judgments, 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 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 prior to 2017, management of the Company modified its approach to revenue recognition as it relates to TANESCO only. The Company records 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. Currently, given the consistent payment pattern from TANESCO, 100% of invoices for gas deliveries was recognized as revenue in Q2, Q3 and Q4 2018.

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.

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, 2018 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, if applicable.

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.

FORWARD LOOKING STATEMENTS

This 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 TPDC future back-in rights on the economic terms of the PSA; ability to meet all conditions under the IFC financing agreement; the Company's estimated spending for the planned Development Program for 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 NNGI ; the potential impact of the 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 ARGA will continue to conduct themselves in accordance with the ARGA until a new gas sales agreement is signed; the Company's expectation that, despite the Re-Rating Agreement of the gas processing plant owned by Songas having expired, the Songas gas processing plant production volumes will not be restricted; the anticipated effect of the Second AGP2 signed in 2017 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 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 NNGI from third parties will replace all or a portion of the volumes currently nominated by TANESCO under the 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 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 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 as a result of the implementation of the new government policies for the oil and gas industry; 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 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 new 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 successfully negotiate agreements; receipt of required regulatory approvals; the ability of the Company to increase production as required to meet demand; 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.

ORCA EXPLORATION GROUP INC.

2018 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 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.

Nigel Friend
Chief Executive Officer

April 10, 2019

Blaine E. Karst
Chief Financial Officer

April 10, 2019

Independent Auditors’ Report

To the Shareholders of Orca Exploration Group Inc.

Opinion

We have audited the consolidated financial statements of Orca Exploration Group Inc. (the “Company”), which comprise:

- the consolidated statements of financial position as at December 31, 2018 and December 31, 2017
- the consolidated statements of comprehensive income (loss) for the years then ended
- the consolidated statements of changes in shareholders’ equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the “financial statements”).

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2018 and December 31, 2017, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (“IFRS”).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the “Auditors’ Responsibilities for the Audit of the Financial Statements” section of our auditors’ report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

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

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in the Financial and Operating Highlights and Management’s Discussion and Analysis filed with the relevant Canadian Securities Commissions.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in the Financial and Operating Highlights and Management’s Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors’ report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors’ report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

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

In preparing the financial statements, management is responsible for assessing the Company’s ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company’s financial reporting process.

Auditors’ Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors’ report that includes our opinion.

Independent Auditors' Report

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represents the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

The engagement partner on the audit resulting in this auditors' report is John Waiand.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada

April 10, 2019

Consolidated Statements of Comprehensive Income (Loss)

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

$'000	Note	**2018**	2017
Revenue	*6, 7*	**57,766**	60,832
Production, distribution and transportation		**(12,378)**	(12,607)
Net production revenue		**45,388**	48,225
Operating expenses			
General and administrative		**(12,827)**	(14,189)
Stock based compensation	*16*	**(4,643)**	(6,619)
Depletion		**(9,495)**	(8,678)
Finance income	*9*	**19,136**	366
Finance expense	*9*	**(15,378)**	(12,831)
Income before tax		**22,181**	6,274
Income tax expense – current	*10*	**(4,588)**	(7,873)
Income tax (expense) recovery – deferred	*10*	**(1,016)**	1,162
Additional Profits Tax	*11*	**(3,014)**	(2,063)
Net income (loss)		**13,563**	(2,500)
Net income attributable to non-controlling interest	*23*	**(293)**	–
Net income (loss) attributable to shareholders		**13,270**	(2,500)
Foreign currency translation (loss) gain from foreign operations		**(83)**	216
Comprehensive income (loss)		**13,187**	(2,284)
Net income (loss) attributable to shareholders per share *($)*			
Basic and diluted	*17*	**0.38**	(0.07)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Financial Position

ORCA EXPLORATION GROUP INC.		AS AT DECEMBER 31	
$'000	Note	2018	2017
Assets			
Current assets			
Cash and cash equivalents		**64,660**	122,322
Investment in short-term bonds	*9*	**66,837**	–
Trade and other receivables	*12*	**15,862**	12,273
Prepayments		**1,217**	866
		148,576	135,461
Non-current assets			
Long-term receivables	*12*	**2,424**	2,797
Investments	*23*	**3,967**	–
Property, plant and equipment	*13*	**107,474**	111,291
		113,865	114,088
Total Assets		**262,441**	249,549
Equity and liabilities			
Current liabilities			
Trade and other payables	*14*	**59,634**	56,758
Tax payable		**–**	718
Deferred revenue	*12*	**–**	8,410
Current portion of long-term loan	*15*	**4,760**	–
		64,394	65,886
Non-current liabilities			
Deferred income taxes	*10*	**12,828**	11,811
Long-term loan	*15*	**53,900**	58,518
Additional Profits Tax	*11*	**37,617**	34,603
		104,345	104,932
Total Liabilities		**168,739**	170,818
Equity			
Capital stock	*16*	**86,508**	86,508
Contributed surplus		**6,319**	6,319
Accumulated other comprehensive loss		**(248)**	(165)
Accumulated income (loss)		**652**	(13,931)
Non-controlling interest	*23*	**471**	–
		93,702	78,731
Total equity and liabilities		**262,441**	249,549

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 24).
The consolidated financial statements were approved by the board on April 9, 2019.

Director

Director

Consolidated Statements of Cash Flows

ORCA EXPLORATION GROUP INC.		YEARS ENDED DECEMBER 31	
$'000	Note	**2018**	2017
Operating activities			
Net Income (loss)		**13,563**	(2,500)
Adjustment for:			
Depletion and depreciation	*13*	**9,660**	9,027
Indirect tax	*9*	**3,689**	3,046
Stock-based compensation expense	*16*	**4,643**	6,619
Deferred income taxes expense	*10*	**1,016**	(1,162)
Additional Profits Tax	*11*	**3,014**	2,063
Unrealized loss on foreign exchange		**(103)**	(261)
Interest expense	*9*	**6,249**	6,250
Participatory interest	*9*	**4,745**	3,809
Change in non-cash operating working capital	*22*	**(17,724)**	21,263
Net cash flows from operating activities		**28,752**	48,154
Investing activities			
Property, plant and equipment expenditures	*13*	**(5,843)**	(1,545)
Change in non-cash working capital	*22*	**792**	(138)
Net cash used in investing activities		**(5,051)**	(1,683)
Financing activities			
Investment in bonds, net	*9*	**(66,837)**	–
Interest paid	*9*	**(6,249)**	(6,250)
Participatory interest paid	*9*	**(6,103)**	–
Proceeds from exercise of options		**–**	992
Proceeds on sale of interest in a subsidiary	*23*	**15,374**	–
Dividends paid to shareholders		**(16,866)**	–
Dividends paid to non-controlling interest	*16*	**(984)**	–
Net cash used in financing activities		**(81,665)**	(5,258)
(Decrease) increase in cash		**(57,964)**	41,213
Cash and cash equivalents at the beginning of the year		**122,322**	80,895
Effect of change in foreign exchange on cash for the year		**302**	214
Cash and cash equivalents at the end of the year		**64,660**	122,322

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

ORCA EXPLORATION GROUP INC.

$'000	**Capital stock**	**Contributed surplus**	**Cumulative translation adjustment**	**Accumulated income (loss)**	**Non-Controlling Interest**	**Total**
Note	*16*			*16*	*23*	
Balance as at December 31, 2017	86,508	6,319	(165)	(13,931)	–	78,731
Dividend declared and paid	–	–	–	(16,866)	–	(16,866)
Foreign currency translation adjustment on foreign operations	–	–	(83)	–	–	(83)
Net income	–	–	–	13,270	293	13,563
Gain on sale of interest in a subsidiary *(Note 23)*	–	–	–	19,163	–	19,163
Non-controlling interest recorded at date of acquisition	–	–	–	–	178	178
Dividend declared and paid non-controlling interest	–	–	–	(984)	–	(984)
Balance as at December 31, 2018	**86,508**	**6,319**	**(248)**	**652**	**471**	**93,702**

$'000	Capital stock	Contributed surplus	Cumulative translation adjustment	Accumulated loss	Total
Note	*16*				
Balance as at December 31, 2016	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

See accompanying 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, 2018 comprise accounts of the Company and its subsidiaries (collectively, the "Company" or "Orca Exploration") and were authorized for issue in accordance with a resolution of the directors on April 9, 2019.

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 ("MoE"), previously known as the Ministry of Energy and Minerals ("MEM"). TANESCO is responsible for the majority of 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

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 Measurement

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 ("$").

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	92%	US dollar
PanAfrican Energy Tanzania Limited	Jersey	92%	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.

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 as incurred.

ii) 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.

Revenue recognition, production sharing agreements and royalties

On January 1, 2018 the Company adopted IFRS 15 – Revenue from Contracts with Customers, which 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. The Company has adopted 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 using the IFRS 15 five step model there were no material changes to net income, the timing of revenue recognized or to opening retained earnings as at January 1, 2018. The Company has expanded disclosures in the notes to its consolidated financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue with the Songas processing and transportation tariff being recorded in production, distribution and transportation costs as opposed to a direct deduction from revenue at bench mark and contractual prices.

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 to all customers at specified delivery points at bench mark and contractual prices A good or service is transferred when the customer obtains control of that good or service. The transfer of control of natural gas occurs at the metering points at the inlet to the customer's facility (see Note 7). 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 revenue". 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 Profit Gas payable to TPDC is adjusted by the amount necessary to fully pay and discharge the Company's liability for taxes on income. Revenue represents the Company's share of Profit Gas and Cost Gas during the period.

The Company records 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).

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. Since April 1, 2018 the Company has recognized 100% of amounts invoiced for TANESCO gas deliveries in revenue as payments from TANESCO for the past 24 months have consistently been higher than amounts invoiced for gas deliveries.

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 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 expected collectability approach to revenue recognition. 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.

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

On January 1, 2018, the Company adopted IFRS 9 - Financial instruments. 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.

The three principal classification categories under the new standard for financial instruments are: measured at amortized cost, fair value through other comprehensive income ("FVOCI") and fair value through profit and loss ("FVTPL"). The classification of financial instruments under IFRS 9 is generally based on the business model in which a financial instrument is managed and its contractual cash flow characteristics. The previous categories under IAS 39 of held to maturity, loans and receivables and available for sale have been removed.

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected loss" model. The new impairment model applies to financial instruments measured at amortized cost, and contract assets and debt investments measured at FVOCI. Under IFRS 9, credit losses will be recognized earlier than under IAS 39.

Cash and cash equivalents, accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities, and bank debt continue to be measured at amortized cost and are now classified as "amortized cost". There were no changes to the Company's classifications of its financial instrument assets and liabilities as FVTPL. None of the Company's financial instruments have been classified as FVOCI.

The Company did not formerly apply hedge accounting to its financial instruments and has not elected to apply hedge accounting to any of its financial instruments upon adoption of IFRS 9. There was no impact to the Company as a result of adopting the new standard.

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. Measurement in subsequent periods depends on the classification of the financial instrument as described below:

- Fair value through profit or loss: financial instruments under this classification include cash and cash equivalents and derivative assets and liabilities.
- Amortized cost: financial instruments under this classification include accounts receivable, investments in bonds, investments, accounts payable and accrued liabilities, dividends payable, finance lease obligations, and long-term debt.

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..

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.

Investments in short-term bonds

Investments in short-term bonds includes highly liquid investments with the original term to maturity of twelve 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 the investments in short-term bonds approximates their carrying amount.

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, 2019 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 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 and IFRIC 4-Determining whether an Arrangement contains a Lease and related interpretations. IFRS 16 is effective for annual reporting periods beginning on or after January 1, 2019. The standard is required to be adopted either retro-spectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect of IFRS as an adjustment to opening retained earnings and applies the standard prospectively. On January 1, 2019, the Company will adopt IFRS 16 and plans to use the modified retrospective approach.

On adoption, the Company currently intends on applying the following practical expedients permitted under the standard. Some expedients are available on a lease-by-lease basis, while others are applicable by class of underlying asset.

i) Any leases with terms ending within 12 months of January 1, 2019 will be recognized as short-term leases and included in the short-term lease disclosure. These leases will not be recognized on the statement of financial position on initial adoption.

ii) The Company will exclude initial direct costs from the measurement of the right-of-use asset on transition for any leases with associated initial direct costs.

iii) Short-term leases and leases of low value assets that have been identified at January 1, 2019, will not be recognized on the statement of financial position. Payments for these leases will be disclosed in the notes to the financial statements.

The Company has completed an initial assessment but not yet finalized the potential impact on its consolidated financial statements. The full impact of applying IFRS 16 on the financial statements in the period of initial application will depend on multiple factors and conditions, including but not limited to, the Company's borrowing rate at January 1, 2019, the composition of the Company's lease portfolio at that date and the Company's latest assessment of whether it will exercise any lease renewal or termination options.

Thus far, the most significant impact identified is that the Company will now recognize new assets and liabilities on its Statement of Financial Position for its office lease. In addition, the nature of the expenses related to those leases will change. Straight-line operating lease expense will be replaced with a depreciation charge for right-of-use assets and interest expense on lease liabilities.

The Company continues to review all existing contracts in detail. The full 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.

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.

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.

The recognition or reversal of deferred tax assets requires 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.

Key sources of estimation of uncertainty

D. Reserves

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 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. To date, TPDC has neither elected to back in within the prescribed notice period nor contributed any costs associated with backing in. For the purpose of the reserves certification as at December 31, 2018 there are no planned drilling activities to the end of the licence.

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

E. Fair value of stock based compensation

All SARs and RSUs granted by the Company are required to be measured at their fair value for each reporting period. 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, (iii) the level of forfeiture, and (iv) the dividend yield.

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.

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 decrease in working capital (defined as current assets less current liabilities) of $0.2 million to $84.0 million and a decrease in the income before tax to $22.0 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, 2018

$'millions	Canadian dollars	Tanzanian shillings	Euros	Other currencies	Total
Cash	0.1	3.7	0.5	0.8	5.1
Trade and other receivables	–	3.2	0.4	0.2	3.8
Trade and other payables	(1.6)	(9.1)	–	(0.2)	(10.9)
Net	(1.5)	(2.2)	0.9	0.8	(2.0)

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, 2018 and 2017, provisions exist against all of the long-term TANESCO receivable, gas plant operations and capital expenditure receivables from Songas, and a receivable of $0.5 million from one industrial customer. No write-off of any receivables occurred in 2018 or 2017 (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 certain TANESCO power plants. The contracts with Songas and TANESCO accounted for 48% of the Company's gross field revenue operating revenue during 2018 and $2.5 million of the short and long-term receivables at year-end.

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. At December 31, 2018 the Company has working capital of $84.2 million which is net of $64.4 million of financial liabilities with regards to trade and other payables of which $40.3 million is due within one to three months, nil is due within three to six months, and $19.4 million is due within six to twelve months (see Note 14).

At the end of the year approximately 66% 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 are made when cash is received for the arrears.

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 to Cost Gas revenue, TANESCO and SONGAS regarding unpaid invoices, and the Tanzanian Revenue Authority ("TRA") in relation to 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.

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.

					YEARS ENDED DECEMBER 31	
	2018			2017		
$'000	ITALY	Tanzania	Total	Italy	Tanzania	Total
External revenue	–	57,766	57,766	–	60,832	60,832
Segment income (loss) (1)	340	12,930	13,270	173	(2,673)	(2,500)
Finance income (2)	–	1,709	1,709	–	366	366
Indirect tax (2)	–	3,689	3,689	–	3,046	3,046
Interest expense (2)	–	10,994	10,994	–	10,059	10,059
Depletion & depreciation	–	9,660	9,660	–	9,027	9,027

					AS AT DECEMBER 31	
	2018			2017		
$'000	Italy	Tanzania	Total	Italy	Tanzania	Total
Capital additions (3)	–	5,843	5,843	–	8,897	8,897
Total assets	748	261,293	262,441	2,041	247,508	249,549
Total liabilities	16	168,723	168,739	493	170,325	170,818

(1) *The income in Italy relates to foreign exchange gains on the euro cash balances held in country as well as the reversal of a provision following VAT recovery.*

(2) *See Note 9.*

(3) *See Notes 12 & 13.*

7 REVENUE

$'000	2018	2017
	YEARS ENDED DECEMBER 31	
Industrial sector	**39,095**	35,440
Power sector	**40,395**	35,916
Gross field revenue	**79,490**	71,356
TPDC share of revenue	**(25,056)**	(17,640)
Company operating revenue	**54,434**	53,716
Current income tax adjustment	**3,332**	7,116
Revenue	**57,766**	60,832

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 Note 12).

The trend from 2017 of TANESCO paying in excess of gas delivered continued in 2018. The Company invoiced TANESCO $31.7 million (2017: $31.1 million) for gas deliveries and received $43.3 million (2017: $46.0 million) in payments during 2018. Based on the consistent payments from TANESCO, the Company: (i) recognized all amounts invoiced for gas deliveries in 2018 as revenue; (ii) recognized $8.4 million (2017: $ nil) of previously deferred revenue as finance income (which represented excess cash received over invoiced amounts for gas deliveries which had not previously been applied against long term TANESCO arrears); and (iii) recognized $8.8 million during the year as finance income relating to the amounts collected during 2018 that were applied towards the long term TANESCO arrears previously provided for.

The Company sells its natural gas to power customers (TANESCO and Songas) and one industrial customer (a cement manufacturer) pursuant to fixed-price contracts. Sales to 37 other industrial customers are at fixed priced discounts (subject to certain floors and ceilings) to the lowest alternative fuel source in Dar es Salaam, Heavy Fuel Oil ("HFO") and coal. Under all contracts, the Company is required to deliver volumes of natural gas to the contract counterparty. Natural gas revenue is recognized when the Company gives up control of the natural gas which occurs at metering points located at the inlets of customers' facilities. The amount of production revenue recognized is based on the agreed transaction price and the volumes delivered.

The Company has entered into contracts with customers with terms ranging from four to eight years.

8 PERSONNEL EXPENSES

$'000	YEARS ENDED DECEMBER 31 2018	2017
Wages and salaries	**8,298**	9,540
Social security costs	**315**	343
Other statutory costs	**378**	330
	8,991	10,213
Stock based compensation (Note 16)	**4,643**	6,619
	13,634	16,832

Wages, salaries and related costs for 2018 of $9.0 million (2017: $10.2 million) are recorded in production, distribution and transportation expenses and general administrative expenses at $2.9 million (2017: $2.0 million) and $6.1 million (2017: $8.2 million), respectively. Personnel expenses include Company employees who operate the plant on behalf of Songas; these expenses are recharged to Songas.

9 FINANCE INCOME AND EXPENSE

Finance income

$'000	YEARS ENDED DECEMBER 31 2018	2017
Interest income	**625**	366
Investment income	**1,084**	–
Reversal of provision for doubtful accounts	**17,427**	–
	19,136	366

The reversal of the provision for doubtful accounts of $17.4 million during the year includes $8.1 million previously recorded as deferred revenue, $7.8 million of excess cash receipts over invoiced gas deliveries during 2018, $1.2 million of operatorship receivables previously charged to Songas and fully provided for at the end of 2017 and $0.3 million previously provided against an outstanding VAT claim (see Notes 7 and 12).

At December 31, 2018 the Company had $66.8 million invested in US dollar short-term bonds with maturity dates from March 2019 to December 2019 and a range of interest rates from 0.875% to 2.125%. The $1.1 million investment income for the year ended December 31, 2018 includes accrued interest of $0.6 million and amortization of the discount on the acquisition of the bonds of $0.5 million. To date the Company has received interest income of $0.7 million. The Company's intent is to hold the bond investments to maturity; however, the bonds are highly liquid by their nature and may readily be liquidated into cash if necessary.

Finance expense

$'000	YEARS ENDED DECEMBER 31 2018	2017
Base interest expense	**6,249**	6,250
Participatory interest expense	**4,745**	3,809
Interest expense	**10,994**	10,059
Net foreign exchange loss (gain)	**695**	(184)
Recovery of provision for doubtful accounts	**–**	(90)
Indirect tax	**3,689**	3,046
	15,378	12,831

Base interest expense and participatory interest expense relate to the long-term loan with the International Finance Corporation ("IFC"). The amount of base interest expense during the year was $6.2 million (2017: $6.3 million); the interest expense is payable quarterly in arrears. The participatory interest expense of $4.7 million (2017: $3.8 million) is paid annually in arrears, it equates to 6.4% 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 increase is related to an additional payment of $2.6 million associated with the sale of the 7.9% interest in PAEM in January 2018 (see Notes 15 and 23).

The indirect tax of $3.7 million for the year (2017: $3.0 million) is for VAT associated with invoices to TANESCO for interest on late payments and invoices under provisions within the PGSA for differences between gas contracted for delivery and gas taken by TANESCO. These amounts are not recognized in the consolidated financial statements due to not meeting the revenue recognition criteria with respect to assurance of collectability (see Note 12).

The recovery of provision for doubtful accounts for the year ended December 31, 2017 of $0.1 million represents a receipt from an industrial debtor which had been previously provided against.

10 INCOME TAXES

The tax charge is as follows:

$'000	YEARS ENDED DECEMBER 31 **2018**	2017
Current tax	**4,588**	7,873
Deferred tax expense (recovery)	**1,016**	(1,162)
	5,604	6,711

Tax of $ nil was paid during the year in relation to the settlement of the prior year's tax liability (2017: $1.4 million). Installment tax payments totaling $5.5 million were made in respect of the current year (2017: $8.7 million). These are presented as a reduction in tax payable on the consolidated statement of financial position.

Tax rate reconciliation

$'000	YEARS ENDED DECEMBER 31 **2018**	2017
Income before tax per Consolidated Statements of Comprehensive Income	**22,181**	6,274
Less Additional Profits Tax	**(3,014)**	(2,063)
Income before statutory tax	**19,167**	4,211
Provision for income tax calculated at the statutory rate of 30%	**5,750**	1,263
Effect on income tax of:		
Administrative and operating expenses	**1,478**	1,732
Foreign exchange loss (gain)	**92**	(47)
Stock-based compensation	**878**	1,596
TANESCO interest not recognized as interest income (Note 9)	**1,936**	1,661
Change in unrecognized tax asset	**(4,903)**	468
Other permanent differences	**373**	38
	5,604	6,711

As at December 31, 2018 the provision for doubtful debt from TANESCO has resulted in a $21.7 million unrecognized deferred tax asset (2017: $23.9 million). If this amount was ultimately not recovered, the Company would also be entitled to a $19.4 million (2017: $17.8 million) recovery of Value Added Tax.

The deferred income tax liability includes the following temporary differences:

	AS AT DECEMBER 31	
$'000	**2018**	2017
Differences between tax base and carrying value of property, plant and equipment	**(24,746)**	(22,444)
Tax recoverable from TPDC	**(2,128)**	(3,378)
Provision for doubtful debt	**2,720**	3,080
Additional Profits Tax	**11,248**	10,381
Unrealized exchange losses/other provisions	**78**	550
	(12,828)	(11,811)

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 Company's forecast Profit Gas over the term of the PSA. The effective APT rate of 19.4% (2017: 19.4%) has been applied to Profit Gas of $15.5 million (2017: $10.6 million). Accordingly, $3.0 million of APT has been recorded as other income tax for the year ended December 31, 2018 (2017: $2.1 million). The Company has yet to earn an annual cash return of 25% and as such, none of the accrued amount is currently payable.

12 TRADE AND OTHER RECEIVABLES

Current receivables

$'000	2018	2017
	AS AT DECEMBER 31	
Trade receivables		
Songas	**2,489**	2,378
Industrial customers	**9,107**	6,915
Less provision for doubtful accounts	**(452)**	(452)
	11,144	8,841
Other receivables		
Songas gas plant operations	**6,496**	5,827
Other	**1,937**	2,521
Less provision for doubtful accounts	**(3,715)**	(4,916)
	4,718	3,432
	15,862	12,273

Trade receivables aged analysis

AS AT DECEMBER 31, 2018

$'000	Current	>30 <60	>60 <90	>90	Total
Songas	1,244	1,245	–	–	**2,489**
Industrial customers	2,213	3,812	1,657	1,425	**9,107**
Less provision for doubtful accounts	–	–	–	(452)	**(452)**
	3,457	5,057	1,657	973	**11,144**

AS AT DECEMBER 31, 2017

$'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

Long-term receivables

$'000	2018	2017
	AS AT DECEMBER 31	
TANESCO receivable	**58,498**	74,361
Provision for doubtful accounts	**(58,498)**	(74,361)
Net TANESCO receivable	**–**	–
VAT Songas workovers	**2,205**	2,205
VAT bond	**–**	363
Lease deposit	**219**	229
	2,424	2,797

TANESCO

At December 31, 2018 the current receivable from TANESCO was $ nil (December 31, 2017: $ nil). 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 $ nil (December 31, 2017: $8.4 million) after the $15.9 million of cumulative excess cash receipts over sales invoiced in 2018 were recorded to the long-term arrears along with the associated reversal of the provision for doubtful accounts (2017: $3.8 million).

The TANESCO long-term trade receivable at December 31, 2018 was $58.5 million with a provision of $58.5 million compared to $74.4 million (with a provision of $74.4 million) at December 31, 2017. Subsequent to December 31, 2018 the Company has invoiced TANESCO $15.6 million for 2018 gas deliveries and TANESCO has paid the Company $18.0 million.

Songas

As at December 31, 2018 Songas owed the Company $9.0 million (December 31, 2017: $8.2 million), while the Company owed Songas $2.2 million (December 31, 2017: $2.0 million). The amounts due to the Company are mainly for sales of gas of $2.5 million (December 31, 2017: $2.4 million) and for the operation of the gas plant of $6.5 million (December 31, 2017: $5.8 million) against which the Company has made a provision for doubtful accounts of $3.7 million (December 31, 2017: $4.9 million). The amounts due to Songas primarily relate to pipeline tariff charges of $1.8 million (December 31, 2017: $1.7 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 $14.5 million were transferred to the cost pool to recover the costs via the PSA cost recovery mechanism. This resulted in:

i) $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 $4.9 million portion of the Songas receivable that had been previously provided for; and

iii) $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 $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:

	December 31, 2017	Year to date transactions	**December 31, 2018**	Post year-end payments and receipts	Outstanding as at the date of this report
Pipeline tariff – payable	(1,670)	(115)	**(1,785)**	1,785	–
Gas sales – receivable	2,378	111	**2,489**	(2,489)	–
Gas plant operation receivable	5,827	669	**6,496**	(930)	5,566
Provision for gas plant operation receivable	(4,916)	1,201	**(3,715)**	–	(3,715)
Other payable	(378)	–	**(378)**	–	(378)
Net balances	1,241	1,866	**3,107**	(1,634)	(1,473)

13 PROPERTY, PLANT AND EQUIPMENT

$'000	**Oil & natural gas interests**	**Leasehold improvements**	**Computer equipment**	**Vehicles**	**Fixtures & fittings**	**Total**
Costs						
As at December 31, 2017	204,266	699	1,487	449	1,126	208,027
Additions	5,744	–	57	–	42	5,843
As at December 31, 2018	**210,010**	**699**	**1,544**	**449**	**1,168**	**213,870**
Accumulated depletion and depreciation						
As at December 31, 2017	93,258	694	1,315	346	1,123	96,736
Depletion and depreciation	9,495	5	94	63	3	9,660
As at December 31, 2018	**102,753**	**699**	**1,409**	**409**	**1,126**	**106,396**
Net book values						
As at December 31, 2018	**107,257**	**–**	**135**	**40**	**42**	**107,474**

$'000	Oil & natural gas interests	Leasehold improvements	Computer equipment	Vehicles	Fixtures & fittings	Total
Costs						
As at December 31, 2016	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 December 31, 2016	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 $7.4 million in relation to the Songas share of workover costs (see Note 12).*

In determining the depletion charge, it is estimated that future development costs of $72.0 million (December 31, 2017: $80.4 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 $5.7 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 $0.2 million (2017: $0.3 million) in general and administrative expenses.

14 TRADE AND OTHER PAYABLES

$'000	2018	2017
	AS AT DECEMBER 31	
Songas	**1,785**	1,670
Other trade payables	**2,725**	1,961
Trade payables	**4,510**	3,631
TPDC Profit Gas entitlement, net	**40,260**	33,422
Accrued liabilities	**14,864**	19,705
	59,634	56,758

TPDC share of Profit Gas

$'000	2018	2017
	AS AT DECEMBER 31	
TPDC Profit Gas entitlement	**40,606**	35,876
Less "Adjustment Factor"	**(346)**	(2,454)
TPDC Profit Gas entitlement, net	**40,260**	33,422

Under the PSA revenue sharing mechanism, the Company is to adjust TPDC's Profit Gas entitlement 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.

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 $60 million. The Loan was fully drawn down in 2016.

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 $5 million starting April 15, 2022 and one final payment of $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 (December 14, 2015), 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 was initially guaranteed by the Company to a maximum of $30 million. The initial 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. Pursuant to the sale of the non-controlling interest in PAEM, the Company agreed with the IFC to reduce the outstanding amount of the loan by the percentage interest sold in PAEM of 7.9% ($4.8 million) on the fourth anniversary of the first drawdown. The Company has provided an additional guarantee to the IFC that if PAET is unable to pay down the loan on or before December 14, 2019, the Company will make the payment. This guarantee is in addition to the Company's initial guarantee.

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 amount of base interest during 2018 was $6.2 million (2017: $6.3 million).

In addition, the Loan initially included an annual variable participatory interest equating to 7.0% 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. The participatory interest charged during 2018 was $4.7 million (2017: $3.8 million). The charge includes an additional payment of $2.6 million (2017: $ nil) associated with the sale of the 7.9% interest in PAEM in January 2018 in accordance with the terms of the Loan (see Note 23). As a result of the additional payment, the annual variable participatory interest is reduced from 7% to 6.45%. At December 31, 2018 the participatory interest included in accrued liabilities is $2.2 million (December 31, 2017: $3.8 million).

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. All amounts under the Loan have been paid when due.

	AS AT DECEMBER 31	
$'000	**2018**	2017
Loan principal	**60,000**	60,000
Financing costs	**(1,340)**	(1,482)
Current portion of loan	**(4,760)**	-
	53,900	58,518

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:

	2018			2017		
Number of shares	**Authorised** *(000)*	**Issued** *(000)*	**Amount** *($'000)*	Authorised *(000)*	Issued *(000)*	Amount *($'000)*
Class A						
As at December 31	**50,000**	**1,750**	**983**	50,000	1,750	983
Class B						
As at December 31	**100,000**	**33,506**	**85,525**	100,000	33,506	85,525
First preference						
As at December 31	**100,000**	**–**	**–**	100,000	–	–
Total Class A, Class B and first preference	**250,000**	**35,256**	**86,508**	250,000	35,256	86,508

All issued capital stock is fully paid.

	2018		2017	
Stock Appreciation Rights ("SARs")	**SARs** *(000)*	**Exercise price** *CDN$*	SARs *(000)*	Exercise price *CDN$*
Outstanding as at January 1	**2,485**	**2.12 to 3.87**	2,430	2.12 to 3.25
Exercised	**(1,270)**	**2.12 to 2.30**	(160)	2.12 to 2.30
Exercised	**(100)**	**2.32 to 2.70**	(165)	2.32 to 2.70
Exercised	**(175)**	**3.02 to 3.25**	(25)	3.02 to 3.25
Exercised	**(85)**	**3.84 to 3.87**	–	–
Granted	**–**	**–**	90	2.12.to 2.30
Granted	**–**	**–**	365	3.84 to 3.87
Forfeited (1)	**(100)**	**2.30**	–	–
Forfeited (1)	**(110)**	**3.84 to 3.87**	(50)	3.84 to 3.87
Outstanding as at December 31	**645**	**2.30 to 3.87**	2,485	2.12 to 3.87

(1) The SARs were forfeited based on the grantee not remaining in employment of the Company for the required vesting period.

The number outstanding, the weighted average remaining life and weighted average exercise prices of SARs at December 31, 2018 were as follows:

Exercise price *(CDN$)*	**Number outstanding** *(000)*	**Weighted average remaining contractual life** *(years)*	**Number exercisable** *(000)*	**Weighted average exercise price** *(CDN$)*
2.30	290	0.12	34	2.30
3.02 to 3.25	235	1.52	55	3.04
3.87	120	3.01	60	3.87
2.30 to 3.87	**645**	**1.20**	**149**	**2.86**

	2018		2017	
Restricted Stock Units ("RSUs")	**RSUs** *(000)*	**Exercise price** *(CDN$)*	RSUs *(000)*	Exercise price *(CDN$)*
Outstanding as at January 1	1,148	0.001	239	0.001
Granted [1]	–	–	1,402	0.001
Exercised	(1,060)	0.001	(493)	0.001
Outstanding as at December 31	**88**	**0.001**	1,148	0.001

[1] *A total of 1,402,322 RSUs were granted during 2017 and were fully vested by March 31, 2018. 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, 2018 were as follows:

Exercise price *(CDN$)*	**Number outstanding** *(000)*	**Number exercisable** *(000)*	**Weighted average remaining contractual life** *(years)*
0.001	**88**	**88**	**3.28**

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 25.3% to 47.4%; 0% dividend yield; 5% forfeiture; a closing stock price of CDN$5.05 per share.

	AS AT DECEMBER 31	
$'000	**2018**	2017
SARs	**1,196**	4,339
RSUs	**364**	3,555
	1,560	7,894

As at December 31, 2018 a total accrued liability of $1.6 million (December 31, 2017: $7.9 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 $4.6 million (2017: $6.6 million) as stock based compensation. The Company stock option plan was terminated in 2018 and there are no stock options outstanding as at December 31, 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.

17 EARNINGS PER SHARE

(000)	2018	2017
	AS AT DECEMBER 31	
Outstanding shares		
Weighted average number of Class A and Class B shares	**35,256**	34,858
Weighted average diluted number of Class A and Class B shares	**35,256**	34,858

The calculation of basic earnings per share is based on a net income attributable to shareholders for the year of $13.3 million (2017: $2.5 million net loss) and a weighted average number of Class A and Class B shares outstanding during the period of 35,256,432 (2017: 34,857,528).

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, 2018 $0.3 million (2017: $0.9 million) was incurred by this firm for services provided.

As at December 31, 2018 the Company has a total of $0.04 million (December 31, 2017: $0.5 million) recorded in trade and other payables in relation to the related parties.

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 ($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 (191 Bcf as at December 31, 2018). 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. In certain respects, the parties thereto are conducting themselves as though the ARGA is in effect. Management does not foresee a material risk with the conduct of the Company's business with an unsigned ARGA at this time.

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 delivery pressure requirements at the Ubungo power plant restrict the infrastructure capacity to a maximum of 97 MMcfd). Songas terminated the Re-Rating Agreement in 2014 although there remains a disagreement as to its current status. Under the terms of the Re-Rating Agreement, the Company paid additional compensation of $0.30/mcf for sales between 70 MMcfd and 90 MMcfd and $0.40/mcf for volumes above 90 MMcfd by issuing credit notes to TANESCO. This was in addition to the tariff of $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 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 NNGI which PAET started to utilize in December 2018.

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 $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, the PGSA was signed (term to June 2023) between TANESCO (as the buyer) and the Company and TPDC (collectively as the seller). TANESCO requested a change to the PGSA MDQ in accordance with clause 7.6(b) which PAET and TPDC approved effective January 29, 2018. The seller is now 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 \$2.98/mcf increased to \$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. On December 22, 2018 a side letter amendment to the PGSA was agreed with TPDC to allow PGSA volumes up to a maximum monthly average volume of 35 MMscf/d to temporarily flow through the NNGI. It is intended that this temporary arrangement is to be replaced by the initialed GSA. The excess and extra charges to TANESCO are not applicable for volumes supplied pursuant to the side letter agreement.

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 \$0.4 million. The agreement in Winchester expires on September 25, 2022 and is at an annual rental of \$0.2 million per annum. The costs of these leases are recognized in the general and administrative expenses. Subsequent to year-end the Company leased offices in London for a twelve-month period for \$0.2 million per annum. The intent is to sub-let the office in Winchester for the duration of the rental agreement but until a sub-let is finalized, the Company continues to make the quarterly rental payments.

Capital Commitments

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. The Company began work on the onshore component of Phase A of the Development Program in 2018 that includes the installation of a refrigeration unit at the Songas Gas processing plant with an estimated cost of \$8.5 million and well workovers with an estimated cost of \$13.6 million. A total of \$4.2 million was incurred on the refrigeration project in 2018 which is scheduled for completion in Q2 2019. A portion of the costs are for workovers on wells SS-3 and SS-4 and assuming that Songas, the owner of the wells, funds the costs for these workovers the estimated workover cost to the Company will be \$5.1 million.

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.

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, 2018, there are no planned drilling activities to the end of the licence.

Cost recovery

TPDC conducted an audit of the historic Cost Pool and in 2011 disputed approximately $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. Subsequent to December 31, 2018 discussions on the disputed amounts resumed with TPDC based on the most recent report published by the Tanzanian attorney general highlighting the lack of progress in resolving the long-standing dispute. At the time of writing this report no independent 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

Area	Period	TAX DISPUTE Reason for dispute	DISPUTED AMOUNTS $'MILLION 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.	1.0	0.7	1.7 (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).	29.0	13.6	42.6 (3)
VAT	2008-10	Output VAT on imported services and SSI Operatorship services.	2.7	2.8	5.5 (4)
			33.0	17.1	50.1

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 $50.1 million (December 31, 2017: $47.2 million).

(1) 2015 ($0.3 million): 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 the TRAB decision which ruled in favour of the 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 the CAT hearing date to be set;

(2) (a) 2005-2009 ($1.6 million): In 2016 TRA filed an application for review of the 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 for their application, under the certificate of urgency, for the CAT to review its judgement. During Q1 2018 CAT ruled in favour of PAET's preliminary objection. In Q4 2018 the TRA applied to the CAT to file an application for review out of time but consequently withdrew its application at the time the Company was preparing to file a preliminary objection against the application. It is not clear whether the TRA will seek to re-file their application;

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

(c) 2012-2015 ($0.0 million): TRA has assessed the Company for withholding tax for services not in the Company's records. Management has objected the assessment and is awaiting TRA response;

(3) (a) 2008 ($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 $1.8 million (with tax impact of $0.6 million). PAET has objected to the assessment for being time-barred, incorrect and arbitrary;

(b) 2009 ($2.6 million): In 2015 TRAB ruled against PAET with respect to timing of deductibility of capital expenditures and other expenses ($1.8 million). In Q2 2017 PAET lost an appeal at TRAT and in July 2018 lost an appeal at CAT. The Company has filed an application for review of the judgement and is awaiting CAT hearing date. In July 2017 TRA sent PAET an amended assessment claiming additional taxes, interest and penalties ($0.8 million). PAET has objected to the assessment for being time-barred and arbitrary and is awaiting a TRA response;

(c) 2010 ($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. The Company is awaiting for a date of hearing at TRAB;

(d) 2011 ($1.9 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 ($1.7 million). The Company is awaiting for a date of hearing at TRAB. 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 ($0.2 million) raised for the year;

(e) *2012 ($15.5 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. Aggrieved by the TRAT decision, the Company filed a Notice of Appeal with the Court of Appeal and is awaiting a hearing date;*

(f) *2013 ($8.2 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 ($1.9 million) which disallowed certain operating costs included in the tax returns and tax on repatriated income ($6.3 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 now is awaiting for a date of hearing at TRAB;*

(g) *2014 ($11.0 million): In 2016 TRA issued an assessment of $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 now is awaiting for a hearing date at TRAB. TRA issued two additional assessments for the year for corporation tax of $4.7 million and tax on repatriated income $3.0 million. PAET has objected the assessments and is awaiting TRA response;*

(h) *2015 ($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 ($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. The appeal was heard on November 1-2, 2018 and the parties are now awaiting for the TRAB judgement; and*

(b) *2012-2014 ($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.*

In 2016 TRA introduced significant changes in relation to the income tax treatment of the extractive sector with new separate chapters in Part V of the Income Tax Act 2004 ("ITA, 2004") for mining and for petroleum to be effective commencing in 2018. Subsequent to this, further changes were made by the Written Laws (Miscellaneous Amendments) Act, 2017 ("WLMAA, 2017") and in particular section 36(a)(ii) of the WLMAA, 2017. The WLMAA, 2017 amended section 65M and 65N of the ITA 2004 to exclude cost oil/cost gas from inclusion in both income and expenditure. The Company is still evaluating the tax effects of the the changes as there are a number of uncertainties and ambiguities as to the interpretation and application of certain provisions of the WLMAA, 2017. In the absence of guidance on these matters and until the 2018 tax returns are finalized which the Company expects to occur in June 2019, the Company expects to use what it believes are reasonable interpretations and assumptions in applying the WLMAA, 2017 for purposes of determining its tax liabilities and results of operations, which may change as it receives additional clarification and implementation guidance.

21 DIRECTORS AND OFFICERS EMOLUMENTS

$'000	Year	Base	Bonus	Stock based compensation expense	Total
Directors	**2018**	**528**	**–**	**583**	**1,111**
Directors	2017	600	–	863	1,463
Officers	**2018**	**1,845**	**–**	**2,116**	**3,961**
Officers	2017	1,668	280	5,372	7,320

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 years ended December 31, 2018 and 2017.

22 CHANGE IN NON-CASH OPERATING WORKING CAPITAL

	YEARS ENDED DECEMBER 31	
$'000	**2018**	2017
Reversal of provision for doubtful accounts	**(16,227)**	(90)
Decrease in trade and other receivables	**8,918**	5,310
Decrease in prepayments	**(351)**	(215)
(Decrease) Increase in trade and other payables	**(9,572)**	20,583
Decrease in tax payable	**(865)**	(2,172)
Decrease (increase) in long-term receivable	**373**	(2,153)
	(17,724)	21,263

23 NON-CONTROLLING INTEREST

On January 16, 2018 the Company sold 7.9 per cent (7,933 Class A common shares) of its subsidiary, PAEM, to a wholly owned subsidiary of Swala Oil & Gas (Tanzania) plc. ("Swala") for $15.7 million cash (net of closing adjustments) and $4.0 million of Swala convertible preference shares pursuant to a share purchase agreement. The preference shares were issued to the Company on June 18, 2018 and entitle the Company to a 10% per annum distribution payable 15 days after each quarter end commencing from the closing date, January 16, 2018. Payment of the quarterly distributions is at the discretion of Swala based on funds available, however, the liability accrues if any amount is unpaid when due. If any distributable amount remains unpaid at December 31, 2021, the Company may demand settlement and Swala is obligated to comply by transferring and returning shares of PAEM sold to Swala; the aggregate value of these shares will equal to the amount of the outstanding distributions. As at December 31, 2018 the Company has not received any distributions or recorded any amount receivable related to the preference shares.

Swala is obligated to redeem 20% of the preference shares for cash annually starting December 31, 2021 until all shares are redeemed. If at any time Swala does not redeem in cash the required number of shares, Swala shall be obligated to redeem the preferred shares by transferring and returning shares of PAEM sold to Swala; the aggregate value of these shares will equal the amount of any outstanding redemption.

Following the issue of the preference shares the Company recorded a further price adjustment of $0.3 million as a result of paying a dividend that was due on closing but withheld pending the issue of the preference shares. This reduced the total cash consideration for tranche one of the transaction to $15.4 million.

The share purchase agreement provided Swala with the right to acquire up to a maximum of 40% of the outstanding Class A shares of PAEM based on the same terms and conditions. Subsequent to December 31, 2018 the Company terminated this right.

A reconciliation of the non-controlling interest is detailed below:

	AS AT DECEMBER 31	
(000)	**2018**	2017
Balance, beginning of period	**–**	–
Recorded at the date of disposition	**178**	–
Share of post-disposition income	**293**	–
Balance, end of period	**471**	–

During the year a dividend of $1.0 million was paid by PAEM to Swala.

24 SUBSEQUENT EVENTS

On January 22, 2019 the Company declared a dividend of CDN$0.05 per share on each of its Class A voting and Class B subordinate voting shares to holders of record as of March 31, 2019 and payable on or about April 30, 2019.

Corporate Information

Board of Directors

Nigel Friend
Executive Director and
Chief Executive Officer

Richmond, London
United Kingdom

David W. Ross
Non-Executive
Director

Calgary, Alberta
Canada

William H. Smith
Non-Executive
Director

Calgary, Alberta
Canada

Glenn D. Gradeen
Non-Executive Director

Calgary, Alberta
Canada

Officers

Nigel Friend
Chief Executive Officer

Richmond, London
United Kingdom

Blaine Karst
Chief Financial Officer

Calgary, Alberta
Canada

Operating Office

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Chief Executive Officer

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