ORCA

ORCA EXPLORATION GROUP INC.

2015 ANNUAL REPORT

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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.

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GLOSSARY

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

Financial and Operating Highlights

(Expressed in US$ unless indicated otherwise)	Year ended/ as at 31 December 2015	2014
OPERATING		
Daily average gas delivered and sold (MMcfd)		
Protected Gas	**38.8**	36.6
Additional Gas	**47.4**	53.2
Industrial	**11.4**	12.6
Power	**36.0**	40.6
Total gas production	**86.2**	89.8
Average price (US$/mcf)		
Industrial	**7.58**	8.61
Power	**3.54**	3.56
Total	**4.49**	4.76
Operating netback (US$/mcf)	**2.57**	2.22
Additional Gas Gross Recoverable Reserves to end of license (Bcf)		
Proved	**368**	450
Probable	**49**	54
Proved plus probable	**417**	504
Net Present Value, discounted at 10% (US$ millions)		
Proved	**309**	379
Proved plus probable	**357**	417
FINANCIAL		
Revenue	**54,088**	56,607
Funds flow from operating activities (1)	**26,571**	32,436
per share - basic and diluted (US$)	**0.76**	0.93
Net cash flows from operating activities	**7,018**	29,757
per share - basic and diluted (US$)	**0.20**	0.85
Net income (loss)	**1,533**	(38,301)
per share - basic and diluted (US$)	**0.04**	(1.10)
Working capital	**32,521**	34,148
Cash	**53,797**	57,659
Capital expenditures	**38,411**	1,312
Long-term loan	**18,599**	–
Outstanding Shares ('000)		
Class A	**1,751**	1,751
Class B	**33,106**	33,164
Total shares outstanding	**34,857**	34,915
Options	**–**	400
Weighted average diluted Class A and Class B shares	**34,887**	34,863

(1) See MD&A - Non-GAAP Measure.

2015 Operating Highlights

- Total Songo Songo field Protected Gas plus Additional Gas deliveries and sales averaged 86.2 standard cubic feet per day ("MMcfd") a decrease of 3% over the prior year (89.8 MMcfd). Additional Gas sales volumes averaged 47.4MMcfd, a decrease of 11% over the prior year (53.2 MMcfd) due largely to declining field productivity for the first nine months of the year together with reduced nominations by the Tanzanian Electrical Supply Company ("TANESCO") and reduced gas sales to Tanzania Portland Cement Company ("TPCC") because of maintenance issues in the first half of the year.
- Power sector sales volumes decreased 11% to 36.0 MMcfd compared to 40.6 MMcfd in the prior year, as a result of a decrease in production from the Songo Songo field due to the natural decline in well deliverability through Q3-2015 and the removal of two TANESCO power plant delivery points by order of the Ministry of Energy and Minerals on 9 September 2015. In accordance with the Portfolio Gas Supply Agreement ("PGSA") with TANESCO, a decrease in field gas production impacts on the volume supplied to the state utility.
- Industrial sales volumes decreased 9% to 11.4 MMcfd compared to 12.6 MMcfd in the prior year. The decrease is primarily due to a reduction in natural gas consumption by a cement company in Dar es Salaam resulting from unscheduled maintenance and the cessation of gas consumption by a textile company at the end of its contract period. These reductions were partly offset by an increase in gas consumption by edible oil companies.
- Average gas prices decreased 6% to US$4.49/mcf compared to US$4.76/mcf in the prior period. Industrial gas prices were down 12% to US$7.58/mcf compared to US$8.61/mcf in the prior year. The decrease is primarily due to a change in sales mix together with a 48% decline in heavy fuel oil ("HFO") prices (to which a majority of Industrial contracts are tied). The decline in the price of HFO is partially mitigated by floor prices in the contracts. Average Power sector gas prices decreased by 1% to US$3.54/mcf compared to US$3.56/mcf in the prior year, the annual indexation increase being counteracted by no sales to TANESCO having been made at the premium pricing as a consequence of decreased nominations.
- Total proved reserves for Additional Gas decreased 18% to 368 Bcf from 450 Bcf in the prior year and total proved plus probable reserves ("2P") decreased 17% to 417 Bcf from 504 Bcf in the prior year. The decrease in both is a consequence of 2015 Additional Gas production of 17.3 Bcf and the slower anticipated growth in Power demand than previously communicated to the Company from the Tanzanian Petroleum Development Corporation ("TPDC"). The net present value of the estimated future cash flows of the 2P reserves at a 10% discount rate ("NPV10") decreased 14% to US$357 million from US$417 million in the previous year. The decline is a result of the fall in anticipated growth of the Power sector revenues which are anticipated to be realized at lower prices. The Company no longer considers it to be realistic that the PGSA gas prices will be rolled out given the industry competition that now exists in Tanzania.
- Revenue decreased 4% to US$54.1 million from US$56.6 million. The fall in revenue is the combination of an 11% fall in total Additional Gas sales volumes, and the 6% fall in the weighted average sale price. The capital investment in the workover programme during the year increased the Company share of net revenue as a consequence of increased Cost Gas and a smaller Profit Gas allocation to TPDC. This helped to offset the overall decline in revenue resulting from the drop in both volumes and prices. Funds flow from operating activities decreased 18% to US$26.6 million or US$0.76 per share basic and diluted, compared to US$32.4 million or US$0.93 per share basic and diluted in the prior period, primarily the result of lower revenue.
- Net income for the year was US$1.5 million or US$0.04 per share basic and diluted, as compared to loss of US$38.3 million or loss of US$1.10 per share in the prior year. The loss in 2014 was primarily due to a US$35.1 million provision against the receivable from TANESCO.
- Working capital as at 31 December 2015 decreased 5% to US$32.5 million compared to US$34.1 million as at 31 December 2014 primarily as a result of moving forward with the development programme offset by a US$20 million increase in long-term debt.

- Total capital expenditures were US$38.4 million for the year. In June 2015 the Company entered into a drilling contract with Paragon Offshore plc for the use of its M826 Mobile Drilling Workover Rig, as well the provision of associated services, in order to execute the offshore phase of the development programme for the Songo Songo gas field (the "Offshore Programme"). The Offshore Programme commenced on 2 September 2015 and included the workovers on three existing wells (SS-5, SS-7 and SS-9) and drilling of one new well, SS-12. All workovers were successfully completed during the year while well SS-12 was successfully completed in February 2016. Upon completion of the Offshore Programme, the rig was released.
- On 29 October 2015, the Company and the International Finance Corporation ("IFC") completed a debt financing agreement for the Company's operating subsidiary, PanAfrican Energy Tanzania Limited to borrow up to US$60 million. The financing is a subordinated, income participating loan with flexible repayment terms and a maximum tenure of approximately 10 years. Drawdowns of the facility are subject to a number of terms and conditions. As at 31 December 2015, US$20 million of the facility had been drawn down, with the remaining US$40 million drawn in February 2016.
- The US$1.2 billion government sponsored Tanzania National Natural Gas Infrastructure Project ("NNGIP") is substantially complete, and the NNGIP gas processing plant on Songo Songo Island is expected to be able to take first gas by April 2016. The Company has submitted a draft gas sales agreement to TPDC to allow direct gas delivery to the NNGIP. Commercial terms remain a key condition to the Company's commitment to expand Songo Songo natural gas sales beyond the existing Songas infrastructure and to supply gas to the NNGIP.
- At the end of 2014 the Company reached and confirmed an understanding with TANESCO that it would only continue to supply gas if TANESCO remained current with payments for current gas deliveries. Excess payments received over and above the current balances would be applied to the arrears balance. In December 2014 as a result of a review the Company established a full provision against the entire long-term receivable of US$52.2 million as at 31 December 2014.
- TANESCO payments for 2015 continued to be irregular. During Q4 2015 TANESCO payments decreased with only US$4.5 million being received against sales of US$11.7 million. As at 31 December 2015 Management has reviewed the current position with TANESCO and feels that the policy implemented in 2014 is still appropriate and as a result, has reclassified a further US$9.8 million, the arrears in excess of 60 days, as long-term debt and has placed a full provision against this. As at the date of this report the total receivable is US$75.4 million.
- During the third quarter of 2015, The Petroleum Act, 2015, (the "Act") was passed into law. The Act repeals earlier legislation, provides a regulatory framework over upstream, mid-stream and downstream gas activity, and consolidates and puts in place a comprehensive legal framework for regulating the oil and gas industry in the country. The 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 bill 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 bill vests TPDC with exclusive rights in the entire petroleum upstream value chain and the natural gas mid and downstream value chain. However, the exclusive rights of TPDC do not extend to mid and downstream petroleum supply operations. The Company is uncertain regarding the potential impact on its business in Tanzania. The Act does provide grandfathering provisions upholding the rights of the Company under their Production Sharing Agreement ("PSA") as it was signed prior to passing of the Act. However, it is still unclear how the provisions of the Act will be interpreted and implemented regarding upstream and downstream activities.
- The Company has an agreement to farm in on Central Adriatic B.R268.RG Permit offshore Italy. Changes in Italian environmental legislation in late 2015 have resulted in the development of this permit being postponed indefinitely. As at the date of this report, the Company has no further capital commitments in Italy.

Gas Reserves

The Company's natural gas reserves as at December 31, 2015 for the period to the end of its license in October 2026 were evaluated by independent petroleum engineering consultants McDaniel & Associates Consultants Ltd. ("McDaniel") 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 24 March 2016 with an effective date of 31 December 2015. A reserves committee of the Company reviews the qualifications and appointment of the independent reserves evaluator and reviews the procedures for providing information to the evaluators. Reserves inluded 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.

During 2015 no significant geological or geophysical data was acquired on or close to the Songo Songo field that might allow a re-assessment of the volumetric gas initially in place ("GIIP") and reserves. The completion of the SS-12 development well in February 2016 encountered the top reservoir approximately 100 meters high to prognosis, and the Company is currently analyzing this new data and its likely impact on the GIIP. The 2015 McDaniel Report has not made any allowance for any additional reserves associated with SS-12.

On a gross Company basis there has been an 18% decrease in Songo Songo's Total Proved Additional Gas reserves to the end of the license period, with no change on a life of field basis, with a total Additional Gas production of 17.3 Bcf during the year. There has been a 17% decrease in the Proved plus Probable Additional Gas reserves on a Gross Company life of license basis from 504.4 to 416.9 Bcf with no change on a life of field basis. The decrease is due to the 2015 production of Additional Gas and the slower anticipated growth in sales of Additional Gas to the NNGIP compared to previous years.

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

Songo Songo	2015		2014	
Additional Gas reserves to October 2026 *(Bcf)*	Gross [1]	Net [2]	Gross	Net
Independent reserves evaluation				
Proved producing	**245.9**	**158.5**	283.6	194.0
Proved undeveloped	**121.9**	**70.5**	166.8	88.9
Total proved *(1P)*	**367.8**	**229.0**	450.4	282.9
Probable	**49.1**	**40.9**	54.0	37.3
Total proved and probable *(2P)*	**416.9**	**269.9**	504.4	320.2

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

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

Songo Songo Additional Gas reserves to end of field life *(Bcf)*	2015 Gross [1]	 Net [2]	2014 Gross	 Net
Independent reserves evaluation				
Proved producing	**598.9**	**375.9**	554.2	359.7
Proved undeveloped	**46.5**	**28.3**	95.1	50.9
Total proved *(1P)*	**645.4**	**404.2**	649.3	410.6
Probable	**116.5**	**76.7**	118.4	76.5
Total proved and probable *(2P)*	**761.9**	**480.9**	767.7	487.1

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

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

For the reserves certification as at 31 December 2015, the McDaniel Report has assumed that TPDC will exercise its right to 'back in' to any additional new field development plans for Songo Songo and consequently will receive a 20% increase in the profit share for the future production emanating from the SSN-1 well. McDaniel has taken the view that this 'back in' right should be treated as a TPDC working interest and therefore the Gross reserves have been adjusted for the volumes of Additional Gas that are allocated to TPDC for their working interest share.

For the purpose of calculating the Gross Additional Gas reserves, McDaniel has assumed in its 2P case that 122 Bcf (2014: 130 Bcf) or an average of 13.5 Bcf per annum will be required to meet the demands of the Protected Gas users from 1 January 2015 to 31 July 2024. During 2015, the Protected Gas users consumed 14.2 Bcf.

	Additional Gas price	**Gross Additional Gas volumes**	**Additional Gas price**	**Gross Additional Gas volumes**
	1P	1P	2P	2P
Year	*US$/mcf*	*MMcfd*	*US$/mcf*	*MMcfd*
2016	3.99	93.10	4.03	93.75
2017	4.10	93.60	4.27	98.49
2018	4.06	108.90	4.27	115.29
2019	4.08	124.70	4.28	137.17
2020	4.18	128.60	4.44	141.46
2021	4.30	132.90	4.63	146.19
2022	4.43	137.21	4.82	155.80
2023	4.56	141.51	4.98	157.00
2024	4.60	145.82	4.98	159.34
2025	4.67	140.63	4.95	166.80
2026	4.96	121.89	4.96	148.83

Gas Reserves

Present value of reserves

The estimated value of the Songo Songo reserves on a life of license basis based on the assumptions on production and pricing are as follows:

	2015			2014		
US$ millions	*5%*	*10%*	*15%*	*5%*	*10%*	*15%*
Proved producing	**294.6**	**229.2**	**184.6**	274.3	195.9	144.3
Proved undeveloped	**114.7**	**79.4**	**55.5**	233.5	182.9	145.1
Total proved (1P)	**409.3**	**308.6**	**240.1**	507.8	378.8	289.4
Probable	**65.9**	**48.8**	**37.7**	60.3	38.4	25.4
Total proved and probable (2P)	**475.2**	**357.4**	**277.8**	568.1	417.2	314.8

There has been a 14% decrease in the 2P present value at a 10% discount basis from US$417 million to US$357 million on a life of license basis.

The decrease in value is predominately a consequence of the slower anticipated power sales to TPDC via the NNGIP Infrastructure. In order to commission the NNGIP gas processing plant in Mtwara in September 2015, the Company under a Government of Tanzania directive was requested to allow connection to the NNGIP Infrastructure of two TANESCO power plants previously supplied under the PGSA contract. The slower than anticipated construction and commissioning of additional power plants has resulted in the inability of the Company to make additional gas sales despite the completion of the Company's offshore component of the development plan jointly approved with TPDC.

Previous reserve reports valuations have been based on the assumption that the PGSA contract would be rolled out for deliveries to the NNGIP infrastructure. Following the connection of the two PGSA delivery points and the continued supply of gas to these plants by a third party, this assumption has been revised using the gas price contemplated for future sales to TPDC for valuation purposes. There is no guarantee that this proposed price will be realized and as such there could be further adjustments to the Company's 2P present value once the negotiations are finalised and a new gas sales agreement is signed with TPDC.

ORCA EXPLORATION GROUP INC.

MANAGEMENT'S DISCUSSION & ANALYSIS

Management's Discussion & Analysis

THIS MD&A OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS SHOULD BE IN CONJUNCTION WITH THE AUDITED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES FOR THE YEAR ENDED 31 DECEMBER 2015. THIS MD&A IS BASED ON THE INFORMATION AVAILABLE ON 14 APRIL 2016.

FORWARD LOOKING STATEMENTS

This management's discussion and analysis ("MD&A") contains forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation. More particularly, this MD&A contains, without limitation, forward-looking statements pertaining to the following: the Company's expectations regarding supply and demand of natural gas; anticipated power sector revenues; potential impact of TPDC future back-in rights on the economic terms of the PSA; the commissioning of the second gas processing facility on Songo Song Island which is part of the National Natural Gas Infrastructure Project ("NNGIP") which included construction and commissioning of two gas processing facilities, a 505 kilometer pipeline supplying gas from the Mtwara Region of Tanzania to Dar es Salaam and a 28 kilometer pipeline supplying gas from Songo Songo Island to the mainland NNGIP; ability to meet all conditions under the International Finance Corporation ("IFC") financing agreement signed on 29 October 2015; the Company's estimated spending for the planned Development Programme for 2016 and 2017, which includes construction of the production platform for well SS-12, tie-in of well SS-12 to the production facilities and implementation of a refrigeration unit to enable production into the NNGIP; the potential impact of the Petroleum Act 2015 on the Company's business in Tanzania; the Company's belief that the parties to the unsigned Amended and Restated Gas Agreement ("ARGA") will continue to conduct themselves in accordance with the ARGA until the new Gas Sales Agreement ("GSA") is signed; the Company's expectation that, despite the Re-Rating Agreement of the gas processing plant owned by Songas Limited ("Songas") having expired, the Songas gas processing plant will not be de-rated and the risk that Songas and the Company will not agree on appropriate terms and sign the GSA in a timely manner; the Company's expectation that it can expand and maintain the deliverability of gas volumes in excess of the existing Songas infrastructure; the Company's expectation that the SS-4 well may need to be suspended in the future; 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 appeal on the decision 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 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, including, but not limited to: failure to receive payments from the Tanzanian Electrical Supply Company ("TANESCO"); risk on timing for the NNGIP to be fully commissioned; risk that the Tanzanian Production Development Corporation ("TPDC"), the Ministry of Energy and Minerals ("MEM") and the Company are unable to agree on commercial terms for future incremental gas sales and consequently the Company cannot expand the Songo Songo development beyond the existing Songas infrastructure and supply gas to the NNGIP; risk that additional gas volumes available to the NNGIP from third parties will replace all or a portion of the volumes currently nominated by TANESCO under the Portfolio Gas Sales Agreement ("PGSA") until additional gas-fired power generation is brought on-stream to consume all of the Company's available gas production; risk that the Development Programme is not completed as planned and the actual cost to complete the Development Programme exceeds the Company's estimates; risk that the remaining well workovers under the Development Programme are unsuccessful or determined to be infeasible; risk that the contingencies related to the development work for the full field development plan for Songo Songo are not satisfied; potential negative effect on the Company's rights under the Production Sharing Agreement ("PSA") and other agreements relating to its business in Tanzania as a result of the recently approved Petroleum Act, 2015, as well as the risk that such legislation will create additional costs and time connected with the Company's business in Tanzania; risk that, without extending or replacing the Re-Rating Agreement, the gas processing plant may be de-rated back to its original capacity, resulting in a material reduction in the Company's sales volumes of Additional Gas; risk that the Company will not fully recover Songas' share of capital expenditures associated with the workovers of wells SS-5 and SS-9; risk that the Company will 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 and changes in how they are interpreted and enforced; increased competition; the lack of availability of qualified personnel or management; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility; competition for, among other things, capital, drilling equipment and skilled personnel; failure to obtain required equipment for drilling; delays in drilling plans; failure to obtain expected results from drilling of wells; effect of changes to the PSA on the Company; changes in laws; imprecision in reserve estimates; the production and growth potential of the Company's assets; obtaining required approvals of regulatory authorities; risks associated with negotiating with foreign governments; inability to satisfy debt obligations and conditions; failure to successfully negotiate agreements; and risk that the Company will not be able to fulfil its contractual obligations. In addition there are risks and uncertainties associated with oil and gas operations, therefore the Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by these forward-looking statements will transpire or occur, or if any of them do so, what benefits the Company will derive therefrom. Readers are cautioned that the foregoing list of factors is not exhaustive.

Such forward-looking statements are based on certain assumptions made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments, as well as other factors the Company believes are appropriate in the circumstances, including, but not limited to, that the NNGIP is completed; the TPDC, the MEM and the Company are able to agree on commercial terms for future incremental gas sales and the Company can expand Songo Songo development beyond the existing Songas infrastructure and supply gas to the NNGIP; the Development Programme will be completed within the timing anticipated; the actual costs to complete the Development Programme are in line with estimates; that there will continue to be no restrictions on the movement of cash from Mauritius or Tanzania; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company will have adequate funding to continue operations; that the Company will successfully negotiate agreements; receipt of required regulatory approvals; the ability of the Company to increase production at a consistent rate; infrastructure capacity; commodity prices will not further deteriorate significantly; the ability of the Company to obtain equipment and services in a timely manner to carry out exploration, development and exploitation activities; future capital expenditures; availability of skilled labour; timing and amount of capital expenditures; uninterrupted access to infrastructure; the impact of increasing competition; conditions in general economic and financial markets; effects of regulation by governmental agencies; that the Company's appeal of various tax assessments will be successful; that the enactment of the Petroleum Act, 2015 in Tanzania will not impair the Company's rights under the PSA to develop and market natural gas in Tanzania; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; and other matters.

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

Management's Discussion & Analysis

NON-GAAP MEASURES

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

- FUNDS FLOW FROM OPERATING ACTIVITIES IS A TERM THAT REPRESENTS CASH FLOW FROM OPERATIONS BEFORE WORKING CAPITAL CHANGES. IT IS A KEY MEASURE AS IT DEMONSTRATES THE COMPANY'S ABILITY TO GENERATE CASH NECESSARY TO ACHIEVE GROWTH THROUGH CAPITAL INVESTMENTS.
- OPERATING NETBACKS REPRESENT THE PROFIT MARGIN ASSOCIATED WITH THE PRODUCTION AND SALE OF ADDITIONAL GAS AND IS CALCULATED AS REVENUES LESS PROCESSING AND TRANSPORTATION TARIFFS, GOVERNMENT PARASTATAL'S REVENUE SHARE, OPERATING AND DISTRIBUTION COSTS FOR ONE THOUSAND STANDARD CUBIC FEET OF ADDITIONAL GAS. THIS IS A KEY MEASURE AS IT DEMONSTRATES THE PROFIT GENERATED FROM EACH UNIT OF PRODUCTION, AND IS WIDELY USED BY THE INVESTMENT COMMUNITY.
- FUNDS FLOW FROM OPERATING ACTIVITIES PER SHARE IS CALCUALATED ON THE BASIS OF THE FUNDS FLOW FROM OPERATING ACTIVITIES DIVIDED BY THE WEIGHTED AVERAGE NUMBER OF SHARES.
- CASH FLOW FROM OPERATING ACTIVITIES PER SHARE IS CALCULATED AS CASH FLOW FROM OPERATIONS DIVIDED BY THE WEIGHTED AVERAGE NUMBER OF SHARES.

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

NATURE OF OPERATIONS

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

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

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

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

TANESCO is a parastatal organization which is wholly-owned by the Government of Tanzania, with oversight by the MEM. TANESCO is responsible for the generation, transmission and distribution of electricity throughout Tanzania. Natural gas has become an integral component of TANESCO's power generation fuel mix as a more reliable source of supply over seasonal hydro power and a more cost effective alternative to liquid fuels. The Company currently supplies gas directly to TANESCO by way of 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. The state utility is the Company's largest customer and the gas supplied by the Company to TANESCO today fires approximately 40% of the electrical power generated in Tanzania.

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.

PRINCIPAL TERMS OF THE TANZANIAN PSA AND RELATED AGREEMENTS

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

Obligations and restrictions

(a) The Company has the right to conduct petroleum operations, market and sell all Additional Gas produced and share the net revenue with TPDC for a term of 25 years, expiring in October 2026.

(b) The PSA covers the two licenses in which the Songo Songo field is located ("Discovery Blocks"). The Proven Section is essentially the area covered by the Songo Songo field within the Discovery Blocks.

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

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

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

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

Access and development of infrastructure

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

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

Revenue sharing terms and taxation

(g) 75% of the gross revenues, less processing and pipeline tariffs and direct sales taxes in any year (net revenue) can be used to recover past costs incurred. Costs recovered out of 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 MEM, 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 MEM has approved the Additional Gas Plan, then TPDC is deemed not to have elected. If TPDC elects to participate, then it will be entitled to a ratable proportion of the Cost Gas and their profit share percentage increases by the Specified Proportion for that development program.

To date, TPDC has neither elected to back in within the prescribed notice period nor contributed any costs associated with backing in, and accordingly the Company has determined that to date there has been no working interest earned by TPDC. For the purpose of the reserves certification as at 31 December 2015, it was assumed that TPDC will 'back-in' for 20% for all future new drilling activities as determined by the current submitted Additional Gas Plan and this is reflected in the Company's net reserve position.

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

In 2011, the Company signed a re-rating agreement with TANESCO and Songas (the "Re-Rating Agreement") to increase the gas processing capacity 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 effectively pays an additional tariff of US$0.30/mcf for sales between 70 MMcfd and 90 MMcfd and US$0.40/mcf for volumes above 90 MMcfd in addition to the tariff of US$0.59/mcf payable to Songas as set by the energy regulator, EWURA.

Under the terms of this agreement, the Company agreed to indemnify Songas for damage to its facilities caused by the re-rating, up to a maximum of US$15 million, but only to the extent that this was not already covered by indemnities from TANESCO's or Songas' insurance policies. The Re-Rating Agreement expired on 31 December 2013. At this time the Company knows of no reason to de-rate the Songas gas processing plant and continues to produce at the higher rated limit and the Company expects this to continue. However, there are no assurances that the ability to produce at the higher rating will continue.

(i) The cost of maintaining the wells and flowlines is split between the Protected Gas and Additional Gas users in proportion to the volume of their respective sales. The cost of operating the gas processing plant and the pipeline to Dar es Salaam is covered through the payment of the pipeline tariff.

(j) 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 net revenues after cost recovery, based on the higher of the cumulative production or the average daily sales. The Profit Gas share 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.

(k) "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.

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

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

Consolidation

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

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

Management's Discussion & Analysis

Results for the year ended 31 December 2015

SUMMARY

The year ended 31 December 2015 saw a decrease from the prior year in 2P reserve volumes of 17% as a result of gas produced during the year, combined with slower anticipated growth in power demand that had been assumed based on forecasts from TPDC. As a result, the net present value of cash flows from 2P reserves at a 10% discount rate decreased 13% compared to the prior year. Production capabilities increased during 2015 as a result of a significant capital expenditure program of US$38.4 million which included the completion of three successful workovers.

The decrease in revenue for 2015 resulted in funds flow from operating activities declining 18% compared to the prior year. A further increase in the provision of the TANESCO long-term receivable also affected profitability, however, the Company was still able to earn a small profit for the year. The Company finished 2015 in a stable financial position with US$32.5 million in working capital and US$18.6 million in long-term debt as a result of the successful completion of a financing facility with the International Finance Corporation.

OPERATING VOLUMES

The total volume of Protected Gas and Additional Gas delivered and sold for the year ended 31 December 2015 was 31,485 MMcf (2014: 32,770 MMcf) or 86.2 MMcfd (2014: 89.8 MMcfd), net of approximately 0.5 MMcfd (2014: 0.8 MMcfd) consumed locally for fuel gas.

The Additional Gas sales volumes for the year were 17,311 MMcf (2014: 19,421 MMcf) or average daily volumes of 47.4 MMcfd (2014: 53.2 MMcfd). This represents a decrease in average daily volumes of 11% year on year.

Additional Gas sales volumes for Q4 2015 were 4,572 MMcf (Q4 2014: 4,461 MMcf) or average daily volumes of 49.7 MMcfd (Q4 2014: 48.5 MMcfd), an increase of 2.5% over the prior year quarter.

The decrease in Additional Gas volumes year over year is primarily the result of declining field productivity, reductions in nominations by TANESCO, and reduced Industrial gas sales volumes during the first nine months of 2015. The increase in Additional Gas sold quarter over quarter is the result of increasing field production as a consequence of successfully working over wells SS-5 and SS-9 during the third and fourth quarters of 2015. These wells were put back into production in Q4 2015.

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

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
	2015	2014	**2015**	2014
Gross sales volume (MMcf)				
Industrial sector	**1,089**	1,084	**4,166**	4,598
Power sector	**3,483**	3,377	**13,145**	14,823
Total volumes	**4,572**	4,461	**17,311**	19,421
Gross daily sales volume (MMcfd)				
Industrial sector	**11.8**	11.8	**11.4**	12.6
Power sector	**37.9**	36.7	**36.0**	40.6
Total daily sales volume	**49.7**	48.5	**47.4**	53.2

Industrial sector

Industrial sales volume decreased by 9% to 4,166 MMcf (11.4 MMcfd) from 4,598 MMcf (12.6 MMcfd) in 2014. The decrease is primarily the result of unscheduled maintenance work by a number of customers together with the cessation of consumption by a textile company at the end of its contract period in June 2015.

Fourth quarter Industrial sales volume increased by 1% to 1,089 MMcf (11.8 MMcfd) from 1,084 MMcf (11.8 MMcfd) in the prior year quarter.

Power sector

Power sector sales volumes decreased by 11% to 13,145 MMcf (36.0 MMcfd), compared to 14,823 MMcf (40.6 MMcfd) in 2014 as a result of decreased production from the Songo Songo field due to deliverability constraints during the first three quarters of 2015, and the decision by TANESCO not to renew a power generation contract with an emergency power plant.

Power sector sales volumes increased by 3% to 3,483 MMcf (37.9 MMcfd), compared to 3,377 MMcf (36.7 MMcfd) in Q4 2014 as a result of an increase in gas production following the successful completion of the well workover programme in Q4 2015. Under the PGSA Gas supply contract, TANESCO is a swing customer receiving less gas in the event of decline in gas production. The increase in gas deliverability as a result of successful workovers has resulted in TANESCO increasing gas consumption levels compared with same quarter in previous year.

SONGO SONGO DELIVERABILITY

As at 31 December 2015, the Company had a field productive capacity of approximately 155 MMcfd, with the expansion of production volumes limited to 102 MMcfd by the available Songas infrastructure. The increase in field productive capacity was due to successful workovers on wells SS-5, SS-7 and SS-9 completed during the fourth quarter of 2015. Well SS-3 is currently suspended and well SS-4 has been shut-in; it is the Company's intention to undertake workovers on both the wells in the future. Subsequent to year-end, the Company completed drilling well SS-12, adding a further 35 MMcfd to the field productive capacity. The SS-12 well cannot be produced until the construction of a platform and flowline to tie the well into the NNGIP infrastructure.

The Company now has significant redundant productive capacity and is planning the installation of refrigeration and compression facilities to ensure production capacity can be maintained well in excess of the volumes required to fill the Songas infrastructure. The Company is currently negotiating an agreement with TPDC for additional gas sales by tying into the NNGIP. Initial volumes sold to TPDC under this agreement would see a concomitant reduction in volumes through the existing Songas infrastructure. This would allow the Company to further increase sales volumes to industrial customers as production capacity would no longer be constrained by the Songas infrastructure.

COMMODITY PRICES

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

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
US$/mcf	**2015**	2014	**2015**	2014
Average sales price				
Industrial sector	**7.62**	8.24	**7.58**	8.61
Power sector	**3.56**	3.49	**3.54**	3.56
Weighted average price	**4.51**	4.64	**4.49**	4.76

i) In Q4 2015 the Company recognised income of US$0.7 million (Q4 2014: US$0.9 million), and for the year to 31 December 2015 US$2.1 million (2014: US$4.2 million), deferred under a take-or-pay provision in an Industrial contract. Under the terms of the contract the customer has three years in which to utilise the deferred income, after which it is released to revenue. These amounts have been deducted from revenue in calculating the average sales prices achieved in the quarter and the year ended 31 December 2015.

Industrial sector

The average gas price achieved during the year was US$7.58/mcf down 12% from (2014: US$8.61/mcf). This is a consequence of several factors (i) a 48% decline in the Heavy fuel Oil (“HFO”) prices in the world market has offset the impact of annual price indexation for Industrial customers and has resulted in the majority of Industrial customers sales, whose prices are tied to HFO prices, being at the contractual floor in accordance with their contracts. The contractual pricing floors having helped to mitigate the impact of a falling HFO price, (ii) the impact of a decline in gas prices on the majority of industrial customers has offset a contractual step change in the gas price to the cement company that came into effect on 1 January 2015, and (iii) a change in the overall sales mix.

The average Industrial gas price for the fourth quarter was US$7.62/mcf down 8% from Q4 2014 (US$8.24/mcf). The impact of prices indexation in January of each year was offset by a decline in HFO prices in the world market. A 1% decrease in the average price in Q4 2015 from the Q3 2015 price of US$7.67/mcf was due to a change in the sales mix.

Power sector

The average sales price to the Power sector was US$3.54/mcf for the year (2014: US$ 3.56 /mcf) a decrease of 1%. The fall in price despite the annual indexation rise of 2% each July under contractual arrangements is a consequence of decreased nominations by TANESCO resulting in fewer sales being made at the premium marginal prices under the PGSA.

The average sales price to the Power sector in the fourth quarter was US$3.56/mcf, up 2% compared with US$3.49/mcf in Q4 2014. The increase is due to annual indexation of the base price in July. The average price for the fourth quarter is down 2% compared to the Q3 2015 price of US$3.62/mcf as a result of a reduction in the volume sold at premium marginal prices under the PGSA.

OPERATING REVENUE

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

The Company is able to recover all costs incurred on the exploration, development and operations of the project up to a maximum of 75% of the net revenue ("Cost Gas") prior to the distribution of Profit Gas. Any costs not recovered in any period are carried forward for recovery out of future revenues. Once the Cost Gas has been recovered, TPDC is able to recover any pre-approved marketing costs.

The Additional Gas sales volumes for 2015 were below 50 MMcfd and, as a consequence, the Company was only entitled to a 40% share of Profit Gas revenue for the year as opposed to a 55% share (net of Cost Gas recoveries from revenue). See "Principal Terms of the Tanzanian PSA and Related Agreements." The Company's share of Profit Gas for the first nine months of 2014 entitled the Company to a 55% share of Profit Gas, this fell to 40% in Q4 2014.

The Company was allocated a total of 74 % of net revenue in 2015 (2014: 63%):

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
US$'000	**2015**	2014	**2015**	2014
Gross sales revenue	**21,288**	21,601	**79,885**	96,566
Gross tariff for processing plant and pipeline infrastructure	**(3,229)**	(3,153)	**(12,282)**	(13,674)
Gross revenue after tariff (net revenue)	**18,059**	18,448	**67,603**	82,892
Analysed as to:				
Company Cost Gas	**13,544**	3,231	**38,689**	12,223
Company Profit Gas	**1,806**	6,902	**11,565**	37,402
Cost pool adjustment	**–**	–	**–**	2,994
Company operating revenue	**15,350**	10,133	**50,254**	52,619
TPDC share of revenue	**2,709**	8,315	**17,349**	30,273
	18,059	18,448	**67,603**	82,892

The Company's total revenues for the quarter and the year ended 31 December 2015 amounted to US$15.9 million and US$54.1 million respectively, after adjusting the Company's operating revenues of US$15.3 million and US$50.3 million by:

i) adding US$0.9 million for income tax for the quarter and US$6.2 million for the year. The Company is liable for income tax in Tanzania, but the income tax is recoverable out of TPDC's Profit Gas when the tax is payable. To account for this, revenue is adjusted to include the current income tax charge grossed up at 30%; and,

ii) subtracting US$0.3 million and US$2.4 million for deferred Additional Profits Tax charged in the quarter and for the year – this tax is considered a royalty and is presented as a reduction in revenue. The APT charge for the prior year includes a reduction in APT of US$0.9 million resulting from the recovery of downstream costs previously and temporarily excluded from the cost recoverable pool. See note on Cost Pool adjustments below.

Management's Discussion & Analysis

Revenue presented on the Consolidated Statement of Comprehensive Income (Loss) may be reconciled to the operating revenue as follows:

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
US$'000	**2015**	2014	**2015**	2014
Industrial sector	**8,794**	9,825	**33,164**	43,763
Power sector	**12,494**	11,776	**46,721**	52,803
Gross sales revenue	**21,288**	21,601	**79,885**	96,566
Processing and transportation tariff	**(3,229)**	(3,153)	**(12,282)**	(13,674)
Net revenue	**18,059**	18,448	**67,603**	82,892
TPDC share of revenue	**(2,710)**	(8,315)	**(17,349)**	(30,273)
Company operating revenue	**15,349**	10,133	**50,254**	52,619
Additional Profits Tax charge	**(335)**	(1,429)	**(2,355)**	(7,280)
Current income tax adjustment	**858**	941	**6,189**	11,268
Revenue	**15,872**	9,645	**54,088**	56,607

Company operating revenue increased 65% in the fourth quarter of 2015 compared with Q4 2014. The increase is primarily due to a capital program to workover three offshore wells and to drill a new offshore well, which commenced in the third quarter of the year. The expenditures substantially increased the pool of recoverable costs. This entitled the Company to 75% of net revenue as Cost Gas in the quarter and the corresponding reduction in Profit Gas also reduced the Profit Gas attributable to TPDC by 67%.

Company operating revenue for the year ended 31 December 2015 is down 4%, being the result of a number of factors. Sales volumes fell 11% which, combined with a 6% reduction in the weighted average sales price, resulted in a 17% drop in gross sales revenue. The processing and transportation tariff was US$1.4 million lower, in line with the reduction in sales volume, giving net revenue of US$67.6 million (2014: US$82.9 million).

In 2015 the Company was able to claim 57% or US$38.7 million (2014: 15% or US$12.2 million) of net revenues as Cost Gas, the increase resulting directly from the workover and drilling program. This increase in Cost Gas is responsible for almost entirely offsetting the effect of reduced prices and sales volumes.

A reduction of US$4.9 million or 67% in the APT charge for the year is the result of a reduction in the effective rate from 21.9% to 20.2% compounded by a fall of 69% in the Company's share of Profit Gas to US$11.6 million (2014: US$37.4 million) on which it is based. The drop in Profit Gas is a direct result of capital expenditure increasing Cost Gas.

The Company's share of revenue in 2014 included an adjustment to the Cost Pool (as defined herein) in respect of downstream costs incurred in prior years, and a further adjustment relating to non-recoverable items agreed by the Company in the course of settling the TPDC Cost Pool audit of 2002 to 2009 is detailed in the table below:

US$'000	YEAR ENDED 31 DECEMBER 2014
Non recoverable costs	(1,024)
Recoverable costs 2011-2013	7,360
Cost Gas recorded in the period	6,336
Reduction in Profit Gas in the period	(3,342)
Net impact on Company share of operating revenue	2,994

PROCESSING AND TRANSPORTATION TARIFF

The Company effectively pays a tariff of US$0.30/mcf for sales between 70 MMcfd and 90 MMcfd and US$0.40/mcf for volumes above 90 MMcfd in addition to the regulated tariff of US$0.59/mcf payable to Songas. The charge for the quarter and for the year were US$3.2 million (Q4 2014: US$3.2 million) and US$12.3 million (2014: US$13.7 million) respectively. The reduction in the tariff for the year is the result of lower volumes during the periods.

PRODUCTION AND DISTRIBUTION EXPENSES

Well maintenance costs are allocated between Protected Gas and Additional Gas in proportion to their respective sales during the period. The total cost of maintenance for the quarter was US$84 thousand (Q4 2014: US$500 thousand) and for the year, US$425 thousand (2014: US$1.2 million). Amounts allocated for Additional Gas for the quarter and for the year were US$47 thousand (Q4 2014: US$277 thousand) and US$233 thousand (2014: US$796 thousand), respectively. The decrease in the year is the result of reduced activity as a consequence of the additional workload associated with the workover programme carried out in the second half of 2015.

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

Distribution costs represent the direct cost of maintaining the ring main distribution pipeline and pressure reduction station (security, insurance and personnel). Ring main distribution costs were US$512 thousand (Q4 2014: US$603 thousand) for the quarter and US$1.9 million (2014: US$2.3 million) for the year. The decrease in maintenance and operating costs is the result of the elimination of the CNG trucking costs for the Mikocheni network. TPDC completed the construction and commissioning of the trunk line from the the Company's Ubungo pressure reducing station ("PRS") to the Company's Mikocheni distribution network in June 2014. The Company signed an agreement with TPDC for the use of their trunk line in June 2014 and pay an interim tariff of $0.52/GJ for the transportation of the natural gas through the TPDC trunk-line. The production and distribution costs are detailed in the table below:

	THREE MONTHS ENDED 31 DECEMBER		**YEAR ENDED 31 DECEMBER**	
US$'000	**2015**	2014	**2015**	2014
Share of well maintenance	**47**	277	**233**	796
Other field and operating costs	**251**	788	**1,594**	2,374
	298	1,065	**1,827**	3,170
Ring main distribution costs	**512**	603	**1,924**	2,323
Production and distribution expenses	**810**	1,668	**3,751**	5,493

OPERATING NETBACKS

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

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
US$/mcf	**2015**	2014	**2015**	2014
Gas price – Industrial	**7.62**	8.24	**7.58**	8.61
Gas price – Power	**3.56**	3.49	**3.54**	3.56
Weighted average price for gas	**4.51**	4.64	**4.49**	4.76
Tariff	**(0.71)**	(0.71)	**(0.71)**	(0.70)
TPDC share of revenue	**(0.59)**	(1.86)	**(1.00)**	(1.56)
Net selling price	**3.21**	2.07	**2.78**	2.50
Well maintenance and other operating costs	**(0.07)**	(0.24)	**(0.13)**	(0.16)
Ring main distribution costs	**(0.11)**	(0.14)	**(0.08)**	(0.12)
Operating netback	**3.03**	1.69	**2.57**	2.22

The operating netback increased by 79% from US$1.69/mcf in Q4 2014 to US$3.03/mcf in Q4 2015. The primary reason for the increase was the 67% decrease in TPDC share of revenue as a consequence of an increase in the Cost Gas recovered, mainly as a result of the workover and drilling programme. In addition, there was a decrease in well maintenance and other operating and distribution costs, largely as a consequence of the work-over activity. This was offset slightly by lower average industrial gas sales prices as a result of a significant decrease in the price of HFO at the world market that has offset the annual price indexation for both industrial and power gas prices, resulting in a decrease in the weighted average price of gas by 3%.

The operating netback for the year increased 16% to US$2.57/mcf from US$2.22/mcf in 2014. The decrease in the weighted average price for the year of 6% was a consequence of a 48% decrease in the price of HFO at the world market and a change in sales mix was offset by a decrease in TPDC's share of revenue on a per MCF basis of 36%, and a decrease in field operating and distribution costs.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses are detailed in the table below:

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
US$'000	**2015**	2014	**2015**	2014
Employee and related costs	**2,796**	2,618	**7,001**	7,115
Stock based compensation (recovery)	**(87)**	(1,101)	**(244)**	3,482
Office costs	**916**	1,060	**3,366**	3,660
Marketing and business development costs	**6**	(25)	**214**	41
Reporting, regulatory and corporate	**1,067**	466	**3,271**	3,346
Other	**–**	195	**–**	270
General and administrative expenses	**4,698**	3,213	**13,608**	17,914

General and administrative expenses include the costs of running the natural gas distribution business in Tanzania which is recoverable as Cost Gas and is relatively fixed in nature. Excluding stock based compensation and other expenses, general and administrative expenses averaged US$1.6 million (Q4 2014: US$1.4 million) per month during the quarter and US$1.1 million (2014: US$1.2 million) per month over the year.

STOCK BASED COMPENSATION

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

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
US$'000	**2015**	2014	**2015**	2014
Stock appreciation rights	**463**	(537)	**(266)**	1,369
Restricted stock units	**(550)**	(564)	**22**	2,113
Stock-based compensation (recovery)	**(87)**	(1,101)	**(244)**	3,482

No stock options were outstanding as at 31 December 2015 compared to 400,000 at the end of 2014. No options were granted during the quarter (Q4 2014: nil).

As at 31 December 2015 a total of 3,100,000 stock appreciation rights ("SARs") were outstanding compared to 2,910,000 as at 31 December 2014. A total of 490,000 SARs were granted in during the year with exercise prices of CDN$3.02 to CDN$3.25, the newly granted SARs have terms of one to five years and vest in equal annual instalments beginning on the first anniversary of the grant date. No RSUs remain outstanding as at 31 December 2015 (2014: 645,199).

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 recognised 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 1.5%; stock volatility of 48.9% to 51.6%; 0% dividend yield; 5% forfeiture; and a closing price of CDN$2.75 per Class B share.

As at 31 December 2015, a total accrued liability of US$1.6 million (2014: US$3.4 million) has been recognised in relation to SARS and RSUs. The Company recognised a credit of US$0.1 million (Q4 2014: credit US$1.0 million) for the quarter and for the year ended 31 December 2015 a credit of US$0.2 million (2014: expense US$3.5 million).

NET FINANCE EXPENSE

The movement in net finance expense is detailed in the table below:

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
US$'000	**2015**	2014	**2015**	2014
Finance income	**20**	12	**43**	98
Interest expense	**(117)**	–	**(117)**	(24)
Net foreign exchange loss	**(370)**	(4,814)	**(2,677)**	(4,437)
Financing fee	**250**	–	**(16)**	–
Provision for doubtful accounts	**(10,731)**	(35,127)	**(11,178)**	(37,047)
Finance expense	**(10,968)**	(39,941)	**(13,988)**	(41,508)
Net finance expense	**(10,948)**	(39,929)	**(13,945)**	(41,410)

The increase in interest expense is a consequence of drawing US$20 million of the IFC loan facility in December 2015.

The foreign exchange loss reflects the impact of movements in the value of the Tanzanian shilling against the US dollar during the period on outstanding customer/supplier balances and bank accounts in Tanzanian shillings.

TANESCO

At 31 December 2015, TANESCO owed the Company US69.7 million, excluding interest, (of which arrears were US$61.9 million) compared to US$59.8 million (including arrears of US$52.2 million) as at 31 December 2014. During the year, the Company received a total of US$34.1 million (2014: US$46.7 million) from TANESCO against sales totaling US$43.6 million (2014: US$54.7 million). Current TANESCO receivables as at 31 December 2015 amounted to US$7.8 million (2014 US$7.7 million). Since the year-end, TANESCO has paid the Company US$4.1 million in 2016, and as at the date of this report the total TANESCO receivable is US$75.4 million (of which US$61.9 million has been provided for). The amounts owed do not include interest billed to TANESCO.

The Company has reached an understanding with TANESCO that it would only continue to supply gas if TANESCO remained reasonably current with payments for current gas deliveries. Excess payments received over and above the current balances would be applied to the arrears balance. TANESCO payments for 2015 continued to be irregular but were sufficient to cover current gas deliveries until the third quarter when payments again were not sufficient to cover current gas deliveries. During Q4 2015 TANESCO payments decreased further with only US$4.5 million being received against sales of US$11.7 million.

Management has reviewed the current position with TANESCO and concluded that the policy to reclassify all amounts receivable from TANESCO in excess of 60 days, and in arrears, as a long-term receivable is still appropriate. As a result, the Company has classified US$9.8 million, the arrears in excess of 60 days, as long-term debt and has recorded a full provision against this.

Management concluded that the continued recognition of TANESCO revenue is appropriate. In arriving at this conclusion management has taken account of:

- Recent discussions with the World Bank, the IMF and IFC during which the Company found strong support for funding to be directed at TANESCO, supported by a recent announcement from the IMF stating the need to address TANESCO debt.
- TANESCO, according to the World Bank, is now making a small profit. With the seasonal increase in available hydro power and new gas to power facilities coming on line later this year, the need for expensive liquid fuel will significantly reduce.
- Most recently, TPDC has co-signed with the Company a commitment from TANESCO establishing a payment plan going forward. This plan was agreed between the Company and TANESCO at the beginning of December 2015, and countersigned by TPDC in January 2016. TANESCO has fallen behind the agreed schedule of payments, but with TPDC signing the agreement and supporting the Company, the Company has a much stronger legal position to pursue collection of arrears.

TAXATION

Income Tax

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

As at 31 December 2015, 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 recognised a deferred tax liability of US$9.1 million (2014: US$7.3 million). During the year there was a deferred tax charge of US$1.7 million compared with a recovery of US$0.5 million in 2014. The deferred tax has no impact on cash flow until it becomes a current income tax, at which point the tax is paid and recovered from TPDC's share of Profit Gas.

Additional Profits Tax

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

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

The effective APT rate of 18.6% (Q4 2014: 20.7%) has been applied to Profit Gas of US$1.8 million (Q4 2014: US$6.9 million) for the quarter, and an average effective rate of 20.2% (2014: 21.9%) has been applied to Profit Gas of US$11.6 million (2014: US$37.4 million) for the year ended 31 December 2015. Accordingly, US$0.3 million (Q4 2014: US$1.4 million) and US$2.4 million (2014: US$7.3 million) has been netted off revenue for the quarter, and for the year ended 31 December 2015, respectively. The 2014 year-to-date APT charge includes a reduction of US$0.9 million, reflecting the impact of recovering downstream costs on cumulative Profit Gas, as a result of the US$3.3 million Profit Gas adjustment identified in the Cost Pool adjustment detailed above.

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
US$'000	**2015**	2014	**2015**	2014
Deferred APT	**335**	1,429	**2,355**	7,280

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 proven reserves. As at 31 December 2015 the proven reserves estimated to have been produced over the term of the PSA license, as evaluated by the independent reservoir engineers, McDaniel & Associates Consultants Ltd., were 368 Bcf (2014: 450 Bcf). A depletion expense of US$2.6 million (Q4 2014: US$3.1 million) for the quarter and US$11.9 million for the year (2014: US$13.6 million) has been recorded in the accounts; the decrease for the year is the result of an 11% decrease in sales volumes and a 1% decrease in the average depletion rate to US$0.69/mcf (2014: US$0.70/mcf).

Non-natural gas properties are depreciated as follows:

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

CARRYING AMOUNT OF ASSETS

Capitalised costs are periodically assessed to determine whether it is likely that such costs will be recovered in the future. To the extent that these capitalised costs are unlikely to be recovered in the future, they are impaired and recorded in earnings.

FUNDS FLOW FROM OPERATING ACTIVITIES

Funds flow from operating activities before working capital changes was US$8.5 million for Q4 2015 (Q4 2014: US$8.7 million) and US$26.6 million (2014: US$32.4 million) for the year and is detailed in the table below:

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
US$'000	**2015**	2014	**2015**	2014
Funds flow from operating activities	**8,508**	8,733	**26,571**	32,436
Working capital adjustments (1)	**(3,058)**	(10,969)	**(19,553)**	(2,679)
Net cash flows from operating activities	**5,450**	(2,236)	**7,018**	29,757
Net cash used in investing activities	**(19,539)**	(718)	**(29,950)**	(1,312)
Net cash from (used in) financing activities	**18,482**	(9)	**18,324**	(1,600)
(Decrease) increase in cash	**4,393**	(2,963)	**(4,608)**	26,845
Effect of change in foreign exchange on cash	**(136)**	(2,494)	**746**	(1,774)
Net (decrease) increase in cash	**4,257**	(5,457)	**(3,862)**	25,071

(1) See Consolidated Statement of Cash Flows

Management's Discussion & Analysis

CAPITAL EXPENDITURES

During 2015 the Company incurred US$38.4 million (2014: US$0.5 million) in capital expenditures relating to the workover of wells SS-5, SS-7, SS-9 and drilling of well SS-12, improvement of Songo Songo infrastructure, and purchase of other equipment. The 2015 capital expenditures are net of recharges of US$11.2 million to Songas for its share of costs on wells SS-5 and SS-9.

	THREE MONTHS ENDED 31 DECEMBER		YEAR ENDED 31 DECEMBER	
US$'000	**2015**	2014	**2015**	2014
Geological and geophysical and well drilling	**23,099**	522	**35,796**	913
Pipelines and infrastructure	**1,382**	193	**2,359**	133
Other equipment	**59**	3	**256**	266
	24,540	718	**38,411**	1,312

WORKING CAPITAL

Working capital as at 31 December 2015 was US$32.5 million (31 December 2014: US$34.1 million) and is detailed in the table below:

	AS AT 31 DECEMBER			
US$'000	2015		2014	
Cash		**53,797**		57,659
Trade and other receivables		**25,391**		49,324
TANESCO	7,831		7,671	
Songas	2,178		23,864	
Industrial customers	6,894		7,532	
Songas gas plant operations	5,631		19,300	
Songas well workover programme	11,209		–	
Other receivables	1,604		773	
Provision for doubtful accounts	(9,956)		(9,816)	
Tax recoverable		**4,519**		11,815
Prepayments		**1,118**		642
		84,825		119,440
Trade and other payables		**49,531**		76,747
TPDC share of Profit Gas	28,208		33,409	
Songas	1,071		28,871	
Other trade payables	11,234		1,961	
Deferred income	667		2,780	
Accrued liabilities	8,351		9,726	
Tax payable		**2,773**		8,545
Working capital (1)		**32,521**		34,148

Notes
(1) Working capital as at 31 December 2015 includes a TANESCO receivable (excluding interest) of US$7.8 million (31 December 2014: US$7.7 million). Management has recorded a provision for doubtful accounts against the long-term receivables in excess of 60 days totaling US$61.9 million (31 December 2014: US$52.2 million). The total of long and short-term TANESCO receivables, including interest, as at 31 December 2015 was US$76.9 million. The financial statements do not recognise the interest receivable from TANESCO as it does not meet IAS 18 income recognition criteria. The Company is however actively pursuing the collection of all the receivables and the interest that has been charged to TANESCO.

Working capital as at 31 December 2015 decreased by 5% over 31 December 2014 and by 18% during the quarter, primarily as a result of having reclassified a further US$9.9 million of TANESCO receivables as long-term and an increase in payables resulting from the 2015 workover and drilling programme. Other significant points are:

- There are no restrictions on the movement of cash from Mauritius or Tanzania, and currently the majority of cash is outside of Tanzania. As at the date of this report, approximately 69% of the Company's cash was held outside of Tanzania.
- Since the quarter end the Company has received US$4.1 million from TANESCO and US$2.1 million from Songas.
- Of the US$6.9 million relating to other trade debtors US$6.1 million had been received as at the date of this report.

The balance of US$28.2 million payable to TPDC represents the remaining balance of its share of revenue as at 31 December 2015.

LONG TERM LOAN

On the 29th October 2015, the Company entered into an agreement with the IFC, a member of the World Bank Group, to provide financing of up to US$60 million for the Company's operating subsidiary, PAET.

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

Base interest on the Loan is payable quarterly at 10% per annum on a 'pay-if-you-can-basis' using a formula to calculate the net cash available for such payments as at any given interest payment date. In addition, an annual variable participatory interest equating to 7% of the cash flow of PAET net of capital expenditures is payable in respect of any given year, commencing with 2016. Such participatory interest survives the repayment and/or maturity of the Loan until 15 October 2026. Dividends and distributions from PAET to the Company are restricted during the term of the Off-Shore Programme and at any time that any amounts of unpaid interest, principal or participating interest are outstanding.

On the 14th December 2015 the Company, through PAET, made an initial drawdown of US$20 million from the available US$60 million. Subsequent to the year-end PAET has drawn the remaining US$40 million. The Offshore Programme was completed on 11 February 2016.

SHAREHOLDERS' EQUITY AND OUTSTANDING SHARE DATA

There were 34,857,110 shares outstanding as at 31 December 2015 as detailed in the table below:

	AS AT 31 DECEMBER	
Number of shares ('000)	**2015**	2014
Shares outstanding		
Class A shares	**1,751**	1,751
Class B shares	**33,106**	33,164
Class A and Class B shares outstanding	**34,857**	34,915
Convertible securities		
Options	**–**	400
Fully diluted Class A and Class B shares	**34,857**	35,315
Weighted average		
Class A and Class B shares	**34,887**	34,863
Convertible securities		
Options	**–**	–
Weighted average diluted Class A and Class B shares	**34,887**	34,863

As at 14 April 2016, there were a total of 1,750,517 Class A common voting shares ("Class A shares") and 33,105,915 Class B subordinated voting shares ("Class B shares") outstanding.

RELATED PARTY TRANSACTIONS

One of the non-executive Directors is a partner at a law firm that provides legal advice to the Company and its subsidiaries. During the quarter, the Company incurred US$0.3 million (Q4 2014: US$0.1 million) and for the year ended 31 December 2015 US$0.6 million (2014: US$0.2 million) to this firm for services provided. The transactions with this related party were made at the exchange amount.

The former Chief Financial Officer who became an Executive Vice-President in November 2015, provided services to the Company through a consulting agreement with a personal services company. During the quarter the Company incurred US$0.2 million (Q4 2014 US$0.1 million) and for the year ended 31 December 2015 US$0.4 million (2014: US$0.6 million) to this firm for services provided.

As at 31 December 2015 the Company has a total of US$0.4 million (2014: US$nil) recorded in trade and other payables in relation to the related parties.

CONTRACTUAL OBLIGATIONS AND COMMITTED CAPITAL INVESTMENT

Protected Gas

Under the terms of the original Gas Agreement for the Songo Songo project ("Gas Agreement"), in the event that there is a shortfall/insufficiency in Protected Gas as a consequence of the sale of Additional Gas, the Company is liable to pay the difference between the price of Protected Gas (US$0.55/MMbtu escalated) and the price of an alternative feedstock multiplied by the volumes of Protected Gas up to a maximum of the volume of Additional Gas sold (145.0 Bcf as at 31 December 2015). 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 a re-rating agreement with TANESCO and Songas (the "Re-Rating Agreement") to increase the gas processing capacity 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 effectively pays an additional tariff of US$0.30/mcf for sales between 70 MMcfd and 90 MMcfd and US$0.40/ mcf for volumes above 90 MMcfd in addition to the tariff of US$0.59/ mcf payable to Songas as set by the energy regulator, EWURA. The Re-Rating agreement expired on 31 December 2013. Since 31 December 2013 production has continued within the higher rated limit and, given the Government's interest in pursuing further development and increasing gas production, the Company expects this to continue. However there are no assurances that this will occur.

Under the terms of this agreement, the Company agreed to indemnify Songas for damage to its facilities caused by the re-rating, up to a maximum of US$15 million, but only to the extent that this was not already covered by indemnities from TANESCO's or Songas' insurance policies.

Portfolio Gas Supply Agreement

On 17 June 2011, a long term (to June 2023) PGSA was signed between TANESCO (as the buyer), the Company and TPDC (collectively as the seller). Under the PGSA, the seller is obligated, subject to infrastructure capacity, to sell a maximum of approximately 37 MMcfd for use in any of TANESCO's current power plants, except those operated by Songas at Ubungo. Under the agreement, the basic wellhead price of approximately US$2.93/mcf increased to US$2.98/mcf on 1 July 2015. Any volumes of gas delivered under the PGSA in excess of 36 MMcfd are subject to a 150% increase in the basic wellhead gas price.

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 1 November 2015 and expires on 31 October 2019 at an annual rent of US$0.4 million. The agreement in Winchester expires on 25 September 2022 and is at an annual rental of US$0.1 million per annum. The costs of these leases are recognised in the general and administrative expenses.

Capital Commitments

Italy

The Company has an agreement to farm in on the Central Adriatic B.R268.RG Permit offshore Italy. The farm-in commits the Company to fund 30% of the Elsa-2 appraisal well up to a maximum of US$11.5 million to earn a 15% working interest in the permit. Thereafter, the Company will fund all future costs relating to the well and the permit in proportion to its participating interest. The Company has also agreed to pay fifteen per cent (15%) of the back costs in relation to the well up to a maximum of US$0.5 million. Changes in Italian environmental legislation in late 2015 have resulted in the development of this permit being postponed indefinitely. As at the date of this report, the Company has no further capital commitments in Italy.

Tanzania

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

Given the completion of the Offshore component of Phase I of the Development Programme in February 2016, which has restored field deliverability and provides sufficient natural gas production to fill the Songas plant and pipeline to capacity for the greater portion of the remaining life of the production license, the Company does not expect to commit to further significant capital expenditures until: (i) agreeing commercial terms with TPDC for the supply of gas to the NNGIP regarding the sale of incremental gas volumes from Songo Songo; and/or (ii) TANESCO arrears have been substantially reduced, guaranteed or other arrangements for payment made which are satisfactory to the Company; and/or (iii) the establishment of payment guarantees with the World Bank or other multi-lateral lending agencies to secure future receipts under any new sales contracts with Government entities.

When conditions are deemed appropriate and there is justification to further improve the reliability/capacity of field deliverability, the Company may contemplate undertaking the remaining part or all of the Phase I Development Programme. The additional costs are estimated to be approximately US$30 million. There is no assurance that financing will be available and on acceptable commercial terms to complete Phase I.

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

CONTINGENCIES

Petroleum Act, 2015

During the third quarter of 2015, The Petroleum Act, 2015, (the "Act") was passed into law. The Act repeals earlier legislation, provides a regulatory framework over upstream, mid-stream and downstream gas activity, and consolidates and puts in place a comprehensive legal framework for regulating the oil and gas industry in the country. The Act also provides for the creation of an upstream regulator, the Petroleum Upstream Regulatory (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 bill 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 bill vests TPDC with exclusive rights in the entire petroleum upstream value chain and the natural gas mid and downstream value chain. However, the exclusive rights of TPDC do not extend to mid and downstream petroleum supply operations. The Company is uncertain regarding the potential impact on its business in Tanzania. The Act does provide grandfathering provisions upholding the rights of the Company under their PSA as it was signed prior to passing of the Act. However, it is still unclear how the provisions of the Act will be interpreted and implemented regarding upstream and downstream activities

TPDC Back-in

TPDC has previously indicated a wish to exercise its right under the PSA to 'back in' to the Songo Songo field development, and a further wish 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.

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

Cost recovery

TPDC conducted an audit of the historic Cost Pool and in 2011 disputed approximately US$34 million of costs that had been recovered from the Cost Pool from 2002 through to 2009. In 2014 TPDC and the Company agreed to remove approximately US$1.0 million from the Cost Pool. In 2015 there have been no further developments. 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. At the time of writing this report no such specialist has been appointed. If the matter is not resolved to the Company's satisfaction, the Company intends to proceed to arbitration via the International Centre for Settlement of Investment Disputes ("ICSID") pursuant to the terms of the PSA.

Taxation

		Tax dispute	Disputed amount US$, million		
Area	**Period**	**Reason for dispute**	**Principal**	**Interest**	**Total**
PAYE	2008-10	Pay-As-You-Earn ("PAYE") withholding tax on taxable income of employees on grossed up equivalent of staff salaries, which are contractually stated as net.	0.3	–	0.3 (1)
WHT	2005-10	WHT on services by non-resident persons performed outside of Tanzania.	1.1	0.8	1.9 (2)
Income Tax	2008-13	Deductibility of capital expenditures and expenses (2009), additional income tax (2008, 2010, 2011), and foreign exchange rate application (2013).	5.2	1.4	6.6 (3)
VAT	2008-10	Output VAT on imported services and SSI Operatorship services.	2.8	3.0	5.8 (4)
			9.4	5.2	14.6

(1) During the year, PAET appealed the Tax Revenue Appeals Board ("TRAB") ruling that PAET is liable to pay PAYE on grossed up equivalent of staff salaries. PAET is awaiting appeal date to be set up with the Tax Revenue Appeals Tribunal ("TRAT");

(2) 2005-2009 (US$1.8 million): During the year, TRAT ruled in favor of PAET. TRA has filed notice of appeal with the Court of Appeal, and PAET is awaiting decision of the Court of Appeal.

2010 (US$0.1 million): TRAB is awaiting a ruling from the Court of Appeal on the 2005-2009 case, which would influence TRAB decision on this matter accordingly.

(3) (a) 2009 (US$1.8 million): During the year, TRAB has ruled against PAET with respect to the deductibility of capital expenditures and expenses. PAET appealed to TRAT and is awaiting hearing date to be scheduled;

(b) 2008, 2010-2011 (US$4.6 million): During the year, PAET filed objections against TRA assessments with respect to additional tax and is awaiting a response;

(c) 2013 (US$ 0.2 million): During the year, PAET filed objections to TRA assessment with respect to foreign exchange rate application and is awaiting a response.

(4) In 2014, PAET filed an objection to TRA's claims and is awaiting a response.

Management, with the advice from its legal counsel, has reviewed the Company's position on the above objections and appeals and has concluded that no provision is required with regard to the above matters.

NEW ACCOUNTING POLICIES

On 06 May, 2014, the IASB issued amendments to IFRS 11, "Accounting for Acquisitions of Interests in Joint Operations". The Company intends to adopt amendments to IFRS 11 in its financial statements for the annual period beginning on January 1, 2016. The Company is currently evaluating the impact of adopting IFRS 11 on its consolidated financial statements.

On May 28 2014, the IASB issued IFRS 15, "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The new standard is effective for annual periods beginning on or after January 1, 2017, with early adoption permitted. The Company intends to adopt IFRS 15 on the finalized adoption date and is currently evaluating the impact of adopting the standard on its consolidated financial statements.

On July 24, 2014, the IASB issued the complete IFRS 9, "Financial Instruments" to replace IAS 39, "Financial Instruments: Recognition and Measurement". IFRS 9 is effective for years beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on its consolidated financial statements.

On January 13, 2016, the IASB issued IFRS 16, "Leases", which replaces IAS 17 "Leases". The new standard introduces a single recognition and measurement model for leases, which would require the recognition of assets and liabilities for most leases with a term of more than twelve months. The new standard is effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the initial adoption date of January 1, 2018. The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The extent of the impact of the adoption of the standard has not yet been determined.

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.

SUMMARY QUARTERLY RESULTS OUTSTANDING

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

Figures in US$'000 except where otherwise stated	**2015**				**2014**			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Financial						restated	restated	restated
Revenue	**15,872**	**15,943**	**12,553**	**9,720**	9,645	14,631	18,854	13,477
Net (loss) income	**(6,468)**	**6,112**	**3,566**	**(1,677)**	(46,381)	4	6,137	1,939
Earnings (loss) per share - basic and diluted (US$)	**(0.19)**	**0.18**	**0.10**	**(0.05)**	(1.32)	–	0.17	0.05
Funds flow from operating activities	**8,508**	**9,462**	**4,889**	**3,712**	8,733	6,641	11,651	5,411
Funds flow per share – basic and diluted (US$)	**0.24**	**0.27**	**0.14**	**0.11**	0.25	0.19	0.33	0.15
Operating netback (US$/mcf)	**3.03**	**2.65**	**2.68**	**1.86**	1.69	2.12	2.92	2.03
Working capital	**32,521**	**39,660**	**38,067**	**34,870**	34,148	42,001	30,399	12,783
Long-term loan	**18,599**	**–**	**–**	**–**	–	–	–	–
Shareholders' equity	**78,154**	**84,476**	**78,480**	**74,944**	76,635	123,004	123,019	116,752
Capital expenditures								
Geological and geophysical and well drilling	**23,099**	**7,578**	**4,135**	**984**	522	273	9	109
Pipeline and infrastructure	**1,382**	**547**	**275**	**155**	193	12	(270)	198
Other equipment	**59**	**150**	**47**	**–**	3	39	48	176
Operating								
Additional Gas sold – industrial (MMcf)	**1,089**	**1,137**	**1,015**	**925**	1,084	1,304	1,046	1,164
Additional Gas sold – power (MMcf)	**3,483**	**3,127**	**3,041**	**3,494**	3,377	3,935	3,503	4,008
Average price per mcf – industrial (US$)	**7.62**	**7.67**	**7.45**	**7.54**	8.24	8.85	9.27	8.11
Average price per mcf – power (US$)	**3.56**	**3.62**	**3.47**	**3.49**	3.49	3.60	3.65	3.52

PRIOR EIGHT QUARTERS

The Company's revenue for the last two years has fluctuated between quarters due to several factors including seasonal issues such as the availability of hydro power, scheduled and unscheduled maintenance by customers resulting in reduced demand, declining well production capacity, a drop in world HFO prices and increased competition for supply of gas within Tanzania. Sales increased in Q4 2015 following completion of the well workover programme which increased the Company's well production capabilities.

The drop in sales in Q4 2014 saw the Company's share of Profit Gas drop from 55% to 40% (see "Principal Terms of the Tanzanian PSA and Related Agreements"), where it has remained. The increase in revenue in the second half of 2015 is directly related to the capital expenditure programme which has permitted the Company to take a significantly increased share of revenue as Cost Gas.

Changes in net income over the last two years have been dominated by TANESCO. In Q4 2014 the Company recorded a US$52.2 million doubtful debts provision against TANESCO arrears. In Q4 2015 an additional US$9.8 million was provided against increased TANESCO arrears. Other significant factors affecting the results were:

- The collapse of the Tanzanian Shilling led to a Q4 2014 exchange loss of US$4.8 million and a further loss of US$1.8 million in Q1 2015.
- In 2014 the Company took a charge of US$3.5 million for stock based compensation, US$4.2 million in Q3.
- In Q4 2014 the Company wrote off US$5.1 million relating to site survey costs for an exploration well which it no longer plans to drill.

Capital expenditure for most of the periods was low. The 2015 workover and drilling programme commenced in Q3 2015 with some preliminary expenditure in Q2.

SELECTED FINANCIAL INFORMATION

Selected annual financial information derived from the audited consolidated financial statements for the years ended 31 December 2015, 2014 and 2013 is set out below:

Figures in US$'000 except per share amount	**2015**	2014	2013
Revenue	**54,088**	56,607	53,482
Funds flow from operating activities	**26,571**	32,436	32,394
Cash flows from operating activities	**7,018**	29,757	22,491
Net income (loss)	**1,533**	(38,301)	(7,640)
Total assets	**189,683**	198,492	207,257
Earnings (loss) in US$ per share:			
Basic and diluted	**0.04**	(1.10)	(0.22)

Revenue decreased by 4% to US$54.1 million in 2015 from US$56.6 million in 2014. The sales volumes were 11% lower in 2015 than 2014, with the weighted average price decreasing 6% from US$4.76/mcf to US$4.49/mcf.

The tax payable in respect of 2015 is US8.0 million (2014: US$11.9 million). Of this, US$4.5 million (2014: US$7.9 million) relating to the current year's profit is, in accordance with the terms of the PSA, recoverable from TPDC. Consequently revenue in 2015 has been uplifted by the gross amount of US$6.2 million (2014: US$11.3 million).

The level of Industrial volumes decreased by 11% to 4,096 MMcf in 2015 from 4,598 MMcf in 2014, mainly as a consequence of unscheduled maintenance work by a number of customers.

The level of Power volumes decreased by 11% to 13,215 MMcf (2014: 14,823 MMcf). The decrease in Power sales resulted from falling gas production and a decision by TANESCO not to renew a contract with an emergency power plant.

Management's Discussion & Analysis

BUSINESS RISKS

Financing

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

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

Collectability of Receivables

The Company evaluates the collectability of its receivables on the basis of payment history, frequency and predictability, as well as Management's assessment of the customer's willingness and ability to pay. Both Songas and the Company have been impacted by TANESCO's inability to pay.

Amounts collected with respect to the long-term receivable in the future will be reflected in earnings when payment is received. Notwithstanding this provision, the Company and TANESCO continue to operate in accordance with the terms of the Portfolio Gas Supply Agreement whereby natural gas continues to be delivered by the Company and TANESCO payments remain reasonably current on current deliveries. This provision against the TANESCO net long-term receivable will not prejudice the Company's rights to payment in full or its ability to pursue collection in accordance with the terms of the agreement with TANESCO.

At 31 December 2015, TANESCO owed the Company US69.7 million excluding interest (of which arrears were US$61.9 million) compared to US$59.8 million (including arrears of US$52.2 million) as at 31 December 2014. During the year, the Company received a total of US$34.1 million (2014: US$46.7 million) from TANESCO against sales totaling US$43.6 million (2014: US$54.7 million). Current TANESCO receivables as at 31 December 2015 amounted to US$7.8 million (2014 US$7.7 million). Since the year-end, TANESCO has paid the Company US$4.1 million in 2016, and as at the date of this report the total TANESCO receivable is US$75.4 million (of which US$61.9 million has been provided for). The amounts owed do not include interest billed to TANESCO.

As at 31 December 2015, Songas owed the Company US$19.0 million (2014: US$43.2 million), whilst the Company owed Songas US$2.6 million (2014: US$30.4 million); there was no contractual right to offset these amounts. Amounts due to Songas primarily relate to pipeline tariff charges of US$ 1.1 million (2014: US$28.9 million), whereas the amounts due to the Company are mainly for capital expenditures of US$11.2 million (2014: US$nil), sales of gas of US$2.2 million (2014: US$23.9 million) and for the operation of the gas plant of US$5.6 million (2014: US$19.3 million). The operation of the gas plant is conducted at cost and the charges are billed to Songas on a flow through basis on a "no profit, no loss" basis.

As at 31 December 2015 the net amount owed by Songas to the Company was US$16.3 million (2014: US$12.7 million). Although significant progress has been made in settling outstanding balances, a doubtful debt provision of US$9.8 million is necessary recognizing the pending settlement of the remaining overdue operatorship charges and the Songas share of the well workover costs. Any significant amounts not agreed to will be pursued through the mechanisms provided in the agreements with Songas.

The "Tax Recoverable" figure carried on the balance sheet arises from the revenue sharing mechanism within the PSA which entitles the Company to recover from TPDC, by way of a deduction from TPDC's Profit Gas share, an amount "the adjustment factor" equal to the actual income taxes payable by the Company. Recovery, by offset against TPDC's share of revenue is dependent on payment of income taxes relating to prior period adjustment factors as they are assessed.

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 will maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavourable event not fully covered by insurance could have a material adverse effect on the Company's financial condition, results of operations and cash flows.

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

Foreign Operations

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

In Tanzania the state retains ownership of the minerals and consequently retains control of, the exploration and production of hydrocarbon reserves. Accordingly, these operations may be materially affected by the Government through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges. The Government of Tanzania issued a National Natural Gas Policy in 2013, which policy 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, 2015 during the past year. 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 regulator, 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.

Corruption remains an issue in Tanzania, the country ranking 117 out of 168 on the 2015 Transparency International Corruption Index. 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 MEM. 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, however that corruption may indirectly affect or otherwise impair the Company's ability to operate in Tanzania and effectively pursue its business plan in that country.

The Tanzania Revenue Authority ("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 and result in assessments, penalties and fines which have not been contemplated by the Company and result 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 monetisation of the Company's reserves through additional gas sales. The Government of Tanzania is close to completing the US$1.2 billion NNGIP that comprises two gas processing plants, one being at Songo Songo, and a pipeline to transport gas from Southern Tanzania to Dar es Salaam. The NNGIP gas processing plant at Songo Songo is expected to be commissioned in the near future. The Company is currently negotiating on commercial terms for the sale of incremental gas volumes however there is no assurance that the Company's gas will be processed and transported to markets on economic terms.

Access to Songas processing and transportation

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

As a result of the Ubungo power plant re-rating that occurred in 2011 pursuant to the Re-Rating Agreement, the capacity of the Songas gas processing plant was increased to a maximum of 110 MMcfd (restricted to 102 MMcfd because of pipeline and pressure requirements). The Re-Rating Agreement expired on 31 December 2013 and no new agreement is currently in place. Without the Re-Rating Agreement, the gas plant capacity may be de-rated to 70 MMcfd (the capacity originally agreed to), which would result in a material reduction in the Company's sales volumes of Additional Gas.

The Petroleum Act, 2015

In July 2015 the Tanzania Parliament passed The Petroleum Act, 2015, which was passed into law by Presidential decree on 4 August 2015. The Act repeals earlier legislation, provides a regulatory framework over mid-stream and downstream gas activity and as well consolidates and puts in place a single, effective and comprehensive legal framework for regulating the oil and gas industry in the country. The Act also provides for the creation of an upstream regulator, the Petroleum Upstream Regulatory (PURA). The mid and downstream petroleum as well as gas activities are proposed to be regulated by the current authority, the Energy and Water Utilities Regulatory Authority (EWURA).

The Act also confers upon TPDC the status of the National Oil Company, mandated with the task of managing the country's commercial interest in the petroleum operations as well as mid and downstream natural gas activities. The Act vests TPDC with exclusive rights in the entire petroleum upstream value chain and the natural gas mid and downstream value chain. However, the exclusive rights of the National Oil Company does not extended to mid and downstream petroleum supply operations.

The Act does provide grandfathering provisions upholding the rights of the Company under the PSA as it was signed prior to passing of the Act. However, it is still unclear how the provisions of the Act will be interpreted and implemented regarding upstream and downstream activities.

Amended and Restated Gas Agreement

The Gas Agreement may be superseded by an initialed ARGA. The unsigned ARGA provides clarification of the Protected Gas volumes and removes all terms dealing with the security of the Protected Gas and contract terms dealing with the consequences of any insufficiency are dealt with in a new Insufficiency Agreement ("IA"). The IA specifies terms under which Songas may demand cash security in order to keep it whole in the event of a Protected Gas insufficiency. Should the IA be signed, it will govern the basis for determining security. Under the provisional terms of the IA, when it is calculated that funding is required, the Company is required to fund an escrow account at a rate of US$2.00/MMbtu on all Industrial Additional Gas sales out of its and TPDC's share of revenue, and TANESCO shall contribute the same amount on Additional Gas sales to the Power sector. The funds provide security for Songas in the event of an insufficiency of Protected Gas. The Company is actively monitoring the reservoir and, supported by the report of its independent engineers, does not anticipate that a liability will occur in this respect. As at the date of this report, the ARGA remains an initialed agreement only, however the parties thereto, in certain respects, are conducting themselves as though the ARGA is in full force and effect. Management does not foresee at this time a material risk with the conduct of the Company's business with an unsigned ARGA.

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 the changes in Italian environmental legislation in late 2015 have resulted in the development of the license 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 organisations 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 developed natural gas market in Tanzania is in its infancy and there is currently limited access to infrastructure with which to serve potential new markets beyond that being constructed by the Company and Songas. The ability of the Company to market any natural gas from current or future reserves in Tanzania may depend upon its ability to develop natural gas markets in Tanzania and the surrounding region, obtain access to the necessary infrastructure to process gas and to deliver sales gas volumes, including acquiring capacity on pipelines which deliver natural gas to commercial markets. The Company is also subject to market fluctuations in the prices of oil and natural gas, uncertainties related to the delivery and proximity of its reserves to pipelines and processing facilities and extensive government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business. The Company is also subject to a variety of waste disposal, pollution control and similar environmental laws.

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

Management's Discussion & Analysis

Additional Gas

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

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

With the enactment of the Petroleum Act, 2015 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 ACT recognises 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 recognised 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 cash 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. There will be no redundant capacity in the production facilities or pipeline until the Company can tie into new facilities or existing facilities are expanded. A loss or material reduction in production capabilities will have a material adverse effect on the total production and funds flow from operations of the Company. Changes in Italian environmental legislation in late 2015 have resulted in the development of the Elsa Italian license being postponed indefinitely.

Environmental and Other Regulations

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

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.

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

In accordance with the terms of the PSA, no provision has been recognised for future decommissioning costs in Tanzania as it is forecast that there will still be commercial gas reserves when the Company relinquishes the license 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.

Management's Discussion & Analysis

Title to Properties

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

Acquisition Risks

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

Reliance on Key Personnel

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

Controlling Shareholder

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

CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

In applying the Company's accounting policies, which are described in Note 4 to the Consolidated Financial Statements, management makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, vary to the actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below:

i) 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 reserve and cash flow information contained herein represents estimates only. The reserves and estimated future net cash flow from the Company's Exploration's properties have been evaluated by McDaniel & Associates Consultants Ltd., 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 31 December 2015 it was assumed that TPDC will 'back-in' for 20% for all future new drilling activities after well SS-12 as determined by the current development plan and this is reflected in the Company's net reserve position.

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

ii) Carrying value of exploration and evaluation assets and property, plant and equipment

The Company assesses its property, plant and equipment for impairment when events or circumstances indicate that the carrying amount of its assets may not be recoverable. If any indication of impairment exists, the Company performs an impairment test on the 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.

iii) 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.

iv) 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 audit by TPDC and potential reassessment in certain circumstances after the elapse of a considerable period of time. Currently approximately US$34 million in cost recoveries for the period 2002 to 2009 have been rejected by TPDC, which audit finding is now the subject of a Notice of Dispute by the Company.

v) Collectability of Receivables

Management reviews the accounts receivable aging and payment history on a weekly basis. Accounts which are in excess of 60-days in arrears are identified as potential doubtful accounts. When sustained arrears performance is exhibited over a quarter, together with an assessment by management of the customer's willingness and ability to pay, an account is deemed "doubtful" and a provision against that account is made for the reporting period based on an assessment of that amount of arrears which are unlikely to be paid in the immediate future.

TANESCO is, and has been, experiencing financial difficulties since 2011. These have been caused by a combination of dependence on high cost power generation based on liquid fuels following severe droughts in Tanzania, a government mandate to provide additional power stations and an inadequate tariff.

The Company has reached an understanding with TANESCO that it would only continue to supply gas if TANESCO remained reasonably current with payments for current gas deliveries. Excess payments received over and above the current balances would be applied to the arrears balance. TANESCO payments for 2015 continued to be irregular but were sufficient to cover current gas deliveries until the third quarter when payments again were not sufficient to cover current gas deliveries. During Q4 2015 TANESCO payments decreased further with only US$4.5 million being received against sales of US$11.7 million.

Management has reviewed the current position with TANESCO and feels that the policy implemented in 2014 to reclassify all amounts receivable from TANESCO in excess of 60 days, and in arrears, as a long-term receivable is still appropriate.

ORCA EXPLORATION GROUP INC.

FINANCIAL STATEMENTS & NOTES

Management's Report to Shareholders

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

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

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

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are properly authorised, 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 external auditors and Management in order to determine if Management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

W. David Lyons
Chairman and Chief Executive Officer

14 April 2016

Blaine E. Karst
Chief Financial Officer

14 April 2016

Independent Auditors' Report

To the Shareholders of Orca Exploration Group Inc.

We have audited the accompanying consolidated financial statements of Orca Exploration Group Inc., which comprise the consolidated statements of financial position as at December 31, 2015 and December 31, 2014, the consolidated statements of comprehensive income (loss), changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Orca Exploration Group Inc. as at December 31, 2015 and December 31, 2014 and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants

14 April 2016
Calgary, Canada

Consolidated Statements of Comprehensive Income (Loss)

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

US$'000	Note	**2015**	2014
Revenue	*6, 7*	**54,088**	56,607
Production and distribution		**(3,751)**	(5,493)
Net production revenue		**50,337**	51,114
Operating expenses			
General and administrative		**(13,608)**	(17,914)
Depletion		**(11,855)**	(13,567)
Asset impairment	*14*	**–**	(5,086)
Operating income		**24,874**	14,547
Net finance expense	*9*	**(13,945)**	(41,410)
Income (loss) before tax		**10,929**	(26,863)
Income tax - current	*10*	**(7,691)**	(11,895)
Income tax - (deferred) recovery	*10*	**(1,705)**	457
Net income (loss)		**1,533**	(38,301)
Foreign currency translation gain from foreign operations		**144**	73
Comprehensive income (loss)		**1,677**	(38,228)
Net income (loss) per share (US$)			
Basic and diluted	*18*	**0.04**	(1.10)
Weighted average shares outstanding (millions)			
Basic and diluted	*18*	**34.9**	34.9

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Financial Position

ORCA EXPLORATION GROUP INC. **AS AT 31 DECEMBER**

US$'000	Note	**2015**	2014
Assets			
Current assets			
Cash and cash equivalents		**53,797**	57,659
Trade and other receivables	*12*	**25,391**	49,324
Tax recoverable	*10*	**4,519**	11,815
Prepayments		**1,118**	642
		84,825	119,440
Non-current assets			
Long-term trade receivable	*12*	**584**	634
Property, plant and equipment	*13*	**104,274**	78,418
		104,858	79,052
Total assets		**189,683**	198,492
Equity and liabilities			
Current liabilities			
Trade and other payables	*15*	**49,531**	76,747
Tax payable		**2,773**	8,545
		52,304	85,292
Non-current liabilities			
Deferred income taxes	*10*	**9,312**	7,606
Long-term loan	*16*	**18,599**	–
Deferred Additional Profits Tax	*11*	**31,314**	28,959
		59,225	36,565
Total liabilities		**111,529**	121,857
Equity			
Capital stock	*17*	**85,488**	85,637
Contributed surplus		**6,347**	6,356
Accumulated other comprehensive loss		**(86)**	(230)
Accumulated loss		**(13,595)**	(15,128)
		78,154	76,635
Total equity and liabilities		**189,683**	198,492

See accompanying notes to the consolidated financial statements.

Nature of Operations (Note 1); Contractual obligations and committed capital investment (Note 20); Contingencies (Note 21).
The consolidated financial statements were approved by the Board of Directors on 14 April 2016.

W H Smith

Director Director

Consolidated Statements of Cash Flows

ORCA EXPLORATION GROUP INC		YEARS ENDED 31 DECEMBER	
US$'000	Note	**2015**	2014
Operating activities			
Net Income (loss)		**1,533**	(38,301)
Adjustment for:			
Depletion and depreciation	*13*	**12,555**	14,197
Asset impairment	*14*	**–**	5,086
Loss on disposal of fixtures and fittings	*13*	**–**	7
Provision for doubtful debts	*9*	**9,908**	37,047
Stock-based compensation (recovery)	*17*	**(244)**	3,482
Deferred income taxes	*10*	**1,705**	(457)
Deferred Additional Profits Tax	*11*	**2,355**	7,280
Interest expense	*9*	**117**	24
Unrealised (gain) loss on foreign exchange		**(1,358)**	4,071
Funds flow from operating activities		**26,571**	32,436
Decrease (increase) in trade and other receivables		**15,222**	(12,840)
Decrease (increase) in tax recoverable		**7,296**	(949)
Increase in prepayments		**(476)**	(361)
(Decrease) increase in trade and other payables		**(35,873)**	18,287
(Decrease) increase in tax payable		**(5,772)**	1,624
Decrease (increase) in long-term receivable		**50**	(8,440)
Net cash flows from operating activities		**7,018**	29,757
Investing activities			
Property, plant and equipment	*13*	**(38,411)**	(1,312)
Change in working capital related to investing activities		**8,461**	–
Net cash used in investing activities		**(29,950)**	(1,312)
Financing activities			
Bank loan repayments		**–**	(1,659)
Interest paid	*9*	**(117)**	(24)
Increase in long-term loan	*16*	**18,599**	–
Normal course issuer bid repurchases	*17*	**(158)**	–
Proceeds from exercise of options		**–**	83
Net cash flow from (used in) financing activities		**18,324**	(1,600)
(Decrease) increase in cash		**(4,608)**	26,845
Cash and cash equivalents at the beginning of the year		**57,659**	32,588
Effect of change in foreign exchange on cash		**746**	(1,774)
Cash and cash equivalents at the end of the year		**53,797**	57,659

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

ORCA EXPLORATION GROUP INC.

US$'000	**Capital stock**	**Contributed Surplus**	**Cumulative translation adjustment**	**Accumulated Loss**	**Total**
Note	17				
Balance as at 1 January 2015	85,637	6,356	(230)	(15,128)	76,635
Normal course issuer bid repurchases	(149)	(9)	–	–	(158)
Foreign currency translation adjustment on foreign operations	–	–	144	–	144
Net income	–	–	–	1,533	1,533
Balance as at 31 December 2015	85,488	6,347	(86)	(13,595)	78,154

US$'000	**Capital stock**	**Contributed surplus**	**Cumulative translation adjustment**	**Accumulated (loss)/income**	**Total**
Note	17				
Balance as at 1 January 2014	85,428	6,482	(303)	23,173	114,780
Options exercised	209	(126)	–	–	83
Foreign currency translation adjustment on foreign operations	–	–	73	–	73
Net loss	–	–	–	(38,301)	(38,301)
Balance as at 31 December 2014	85,637	6,356	(230)	(15,128)	76,635

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

General Information

Orca Exploration Group Inc. was incorporated on 28 April 2004 under the laws of the British Virgin Islands. 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 31 December 2015 comprise accounts of the Company and all its wholly owned subsidiaries (collectively, the "Company" or "Orca Exploration") and were authorised for issue in accordance with a resolution of the directors on 14 April 2016.

1 NATURE OF OPERATIONS

The Company's principal operating asset is its interest 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) 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.

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

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

The Tanzania Electric Supply Company Limited ("TANESCO") is a parastatal organization which is wholly-owned by the GoT, with oversight by the Ministry of Energy and Minerals ("MEM"). TANESCO is responsible for the generation, transmission and distribution of electricity throughout Tanzania. The Company currently supplies gas directly to TANESCO by way of a Portfolio Gas Supply Agreement ("PGSA") and indirectly through the supply of Protected Gas and Additional Gas to Songas which in turn generates and sells power to TANESCO. The state utility 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 consisting of some 38 industrial customers.

2 BASIS OF PREPARATION

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

A. Statement of Compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB").

B. Basis of consolidation

Subsidiaries

The consolidated financial statements include the accounts of Orca Exploration Group Inc. and all its wholly owned subsidiaries (collectively, the "Company"). 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	Mauritius	100%	US dollar
PanAfrican Energy Tanzania Limited	Jersey	100%	US dollar
Orca Exploration UK Services Limited	United Kingdom	100%	British Pound

Transactions eliminated upon consolidation

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

C. 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

Orca Exploration Italy Inc. and Orca Exploration Italy Onshore Inc. has the Euro and Orca UK Services has British pound sterling as their functional currencies. The assets and liabilities of these companies are translated into US dollars at the period-end exchange rate. The income and expenses of the companies are translated into US dollars 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.

A. Exploration and evaluation assets, property plant and equipment

i) Exploration and evaluation assets

Exploration and evaluation costs are capitalised as intangible assets. Intangible assets includes lease and license 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, together with leasehold improvements, computer equipment, motor vehicles and fixtures and fittings and are 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 capitalised. The cost associated with tangible natural gas assets are amortised on a field by field unit of production method based on commercial proven reserves. The calculation of the unit of production amortisation takes into account the estimated future development cost of the field.

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 whether there is any indication that those assets have suffered an impairment loss. 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 recognised for the CGU in prior years. A reversal of an impairment loss is recognised as income immediately.

B. Operatorship

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

C. 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 recognised as an expense in the income statement as incurred.

ii) Stock options

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

iii) Stock appreciation rights and restricted stock units

Stock appreciation rights ("SARs") and restricted stock units ("RSUs") are issued to certain key managers, officers, directors and employees. The fair value of SARs and RSUs is expensed in the statement of comprehensive loss 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.

D. Asset retirement obligations

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

Notes to the Consolidated Financial Statements

E. Revenue recognition, production sharing agreements and royalties

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

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

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

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

Since 2011 TANESCO has experienced financial difficulties due to its dependence on high cost power generation based on liquid fuels following severe draughts in Tanzania. Whilst the Company has received assurances from the Government of Tanzania that it was arranging financing for TANESCO, the receivables continued to build.

The Company has reached an understanding with TANESCO that it would only continue to supply gas if TANESCO remained reasonably current with payments for current gas deliveries. Excess payments received over and above the current balances would be applied to the arrears balance. TANESCO payments for 2015 continued to be irregular but were sufficient to cover current gas deliveries until the third quarter when payments again were not sufficient to cover current gas deliveries. During Q4 2015 TANESCO payments decreased further with only US$4.5 million being received against sales of US$11.7 million. Management has reviewed the current position with TANESCO and feels that the policy implemented in 2014 to reclassify all amounts receivable from TANESCO in excess of 60 days, and in arrears, as a long-term receivable is still appropriate. As a result, the Company has classified a further US$9.8 million, the arrears in excess of 60 days, as long-term debt and has placed a full provision against this (see Note 12). The current total provision is US$61.9 million (2014: US$52.2 million).

F. 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. This tax is considered to be a royalty and is netted against revenue. Deferred APT is provided for by forecasting the total APT payable as a proportion of the forecast Profit Gas over the term of PSA license. 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 programme.

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.

G. 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 realisation or settlement of carrying amounts of assets and liabilities using tax rates substantively enacted at the balance sheet date. A deferred tax asset is recognised only to the extent that it is probable that future taxable profits will be available against which the asset can be utilised. Deferred tax assets are reduced to the extent that it is no longer probable that the related tax benefits will be realised.

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.

H. 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

I. Financial instruments

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

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

Initial recognition

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

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

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

ii) **Loans and receivables:**

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

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

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

iii) **Other financial liabilities:**

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

Cash and cash equivalents

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

Impairment of financial assets

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

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

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

J. Contributed surplus

This is used to record two types of transactions:

i) To recognise the fair value of equity settled stock based compensation expensed in the year.

ii) To account for the difference between the aggregated book value of the shares purchased under the normal course issuer bid and the actual consideration.

K. Earnings or loss per share ("EPS")

Basic earnings or loss per share is calculated by dividing net income (loss) attributable to owners of the Company (the numerator) by the weighted average number of ordinary shares outstanding (the denominator) during the period. The denominator is calculated by adjusting the shares outstanding at the beginning of the period by the number of shares bought back or issued during the period, multiplied by a time-weighting factor.

Diluted EPS is calculated by adjusting the earnings and number of shares for the effects of all dilutive potential ordinary shares deemed to have been converted at the beginning of the period or if later, the date of issuance. The effects of anti-dilutive potential ordinary shares are ignored in calculating diluted EPS. All options are considered anti-dilutive when the Company is in a loss position.

L. New accounting standards and interpretations

On May 28 2014, the IASB issued IFRS 15, "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The new standard is effective for annual periods beginning on or after January 1, 2017, with early adoption permitted. The Company intends to adopt IFRS 15 on the finalized adoption date and is currently evaluating the impact of adopting the standard on its consolidated financial statements.

On July 24, 2014, the IASB issued the complete IFRS 9, "Financial Instruments" to replace IAS 39, "Financial Instruments: Recognition and Measurement". IFRS 9 is effective for years beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on its consolidated financial statements.

On January 13, 2016, the IASB issued IFRS 16, "Leases", which replaces IAS 17 "Leases". The new standard introduces a single recognition and measurement model for leases, which would require the recognition of assets and liabilities for most leases with a term of more than twelve months. The new standard is effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the initial adoption date of January 1, 2018. The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The extent of the impact of the adoption of the standard has not yet been determined.

Notes to the Consolidated Financial Statements

4 USE OF ESTIMATES AND JUDGEMENTS

In applying the Company's accounting policies, which are described in Note 3, management makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, vary to the actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below:

A. 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 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. ("McDaniel"), 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 31 December 2015 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.

B. Carrying value of exploration and evaluation assets and property, plant and equipment

The Company assesses its property, plant and equipment for impairment when events or circumstances indicate that the carrying amount of its assets may not be recoverable. If any indication of impairment exists, the Company performs an impairment test on the 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.

C. 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 (see Note 12).

D. 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.

E. 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.

F. Financial instrument classification and measurement

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

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

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

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

Notes to the Consolidated Financial Statements

5 RISK MANAGEMENT

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

A. Foreign exchange risk

Foreign exchange risk arises when transactions and recognised 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 un-restricted, 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. The majority of the consultants' contracts are denominated in British pounds sterling. All of the capital stock, equity financing and any associated stock based compensation are denominated in Canadian dollars. All of the operational revenue and the majority of capital expenditure are denominated in US dollars.

There are no forward exchange rate contracts in place.

A 10% increase in the US dollar against the relevant foreign currency would result in an overall increase in working capital (defined as current assets less current liabilities) of US$0.7 million to US$33.1 million and an increase in the income before tax to US$11.1 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, 2015 *US$'000*	**Canadian dollars**	**Tanzanian shillings**	**Euros**	**Other**	**Total**
Cash	0.4	2.0	0.8	3.8	7.0
Trade and other receivables	–	4.9	0.1	0.9	5.9
Trade and other payables	(2.0)	(2.4)	(0.9)	(0.1)	(5.4)
	(1.6)	4.5	–	4.6	7.5

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 of December 31, 2015 and 2014, other than the provisions against the long-term TANESCO receivable and gas plant operations charges/capital expenditure receivables from Songas, the Company does not have an allowance for doubtful accounts against any other receivables nor was it required to write-off any receivables (see Note 12).

All of 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 approximately 37 MMcfd of gas. The contracts with Songas and TANESCO accounted for 58% of the Company's operating revenue during 2015 and US$71.9 million of the short and long-term receivables prior to provision at year-end.

TANESCO has continued to experience financial difficulties during 2015, which has resulted in irregular and inconsistent payments for gas deliveries. As a result management has placed a provision for doubtful debts against the entire amount of arrears due from TANESCO in the amount of US$61.9 million as at 31 December 2015 (31 December 2014 US$52.2 million).

Sales to the Industrial sector, currently 38 customers, are subject to an internal credit review to minimize the risk of non-payment.

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

E. Liquidity risk

Liquidity risk is the risk that the Company will not have sufficient funds to meet its liabilities. Cash forecasts identifying liquidity requirements of the Company are produced on a regular basis. These are reviewed to ensure sufficient funds exist to finance the Company's current operational and investment cash flow requirements. The Company has US$49.5 million of financial liabilities with regards to trade and other payables of which US$48.6 million is due within one to three months, nil is due within three to six months, and US$0.9 million is due within six to twelve months (see Note 15). As at year-end the Company had a current tax liability of US$2.4 million.

At the end of the year a significant proportion of the current liabilities relate to TPDC. The amounts due to TPDC represent its share of Profit Gas; however given the difficulties in collecting from TANESCO, the Company has been settling and intends to continue to settle these amounts on a pro rata basis in accordance with amounts received from TANESCO (see Note 12).

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 optimisation of capital structure as many sources of traditional capital are unavailable.

G. Country risk

Prior to 2014 an allegation had been made by TPDC that the Company had over-recovered approximately US$21 million in Cost Gas revenue. This resulted in Parliament advising the GoT to take action to terminate the Company's PSA. In response to a Notice of Dispute delivered by the Company in March 2014, TPDC retracted the allegation. In the opinion of management, the retraction exonerated the Company and to this date, no further action has been taken by Parliament or the Government against the Company related to the allegations. Accordingly, the Company continues to rely upon its rights under the existing PSA and has initiated notices of dispute to resolve any remaining issues. The Company has put in place an advisory committee of experienced individuals with significant experience working with the Tanzanian government to mitigate the risks of doing business in Tanzania.

Notes to the Consolidated Financial Statements

6 SEGMENT INFORMATION

The Company has one reportable industry segment which is international exploration, development and production of petroleum and natural gas. The Company currently has producing and exploration assets in Tanzania and had exploration and appraisal interests in Italy (see Note 20).

	2015			2014		
US$'000	**Italy**	**Tanzania**	**Total**	**Italy**	**Tanzania**	**Total**
External revenue	**–**	**54,088**	**54,088**	–	56,607	56,607
Segment income (loss)	**(167)**	**1,700**	**1,533**	(6)	(38,295)	(38,301)
Non-cash charge [1]	**–**	**(9,908)**	**(9,908)**	–	37,047	37,047
Depletion & depreciation	**–**	**12,555**	**12,555**	–	14,197	14,197
Asset impairment	**–**	**–**	**–**	–	5,086	5,086
Capital additions	**–**	**38,411**	**38,411**	–	1,312	1,312
Total assets	**1,621**	**188,062**	**189,683**	1,931	196,561	198,492
Total liabilities	**131**	**111,398**	**111,529**	272	121,585	121,857

(1) Non-cash charge represent amounts provided for doubtful accounts receivable from TANESCO.

7 REVENUE

US$'000	YEARS ENDED 31 DECEMBER 2015	2014
Industrial sector	**33,164**	43,763
Power sector	**46,721**	52,803
Gross sales revenue	**79,885**	96,566
Processing and transportation tariff	**(12,282)**	(13,674)
Net revenue	**67,603**	82,892
TPDC share of revenue	**(17,349)**	(30,273)
Company operating revenue	**50,254**	52,619
Additional Profits Tax charge	**(2,355)**	(7,280)
Current income tax adjustment	**6,189**	11,268
Revenue	**54,088**	56,607

The Company's total revenues for the year amounted to US$54.1 million after adjusting the Company's operating revenue of US$50.3 million by:

i) adding US$6.2 million for income tax for the current year. The Company is liable for income tax in Tanzania, but the income tax is recoverable out of TPDC's Profit Gas when the tax is payable. To account for this, revenue is adjusted to include the current income tax charge grossed up at 30% (see Note 10); and,

ii) subtracting US$2.4 million for deferred Additional Profits Tax charged in the year – this tax is considered a royalty and is presented as a reduction in revenue.

Cost Pool adjustments

In 2014, the Company formally advised TPDC that the downstream business will remain under the PSA and that related costs would be recovered in accordance with the terms of the PSA and would no longer be held separately. As a result of recovering this expenditure, the results for 2014 reflect a reallocation of Cost Gas and Profit Gas between TPDC and the Company.

The following table shows the impact on the Company's 2014 operating revenue resulting from adjusting the cost pool. The net amount which is included in the Company's operating revenue of US$52.6 million has been recovered from TPDC's share of revenue:

US$'000	YEAR ENDED 31 DECEMBER 2014
Non-recoverable costs	(1,024)
Recoverable costs 2011-2013	7,360
Cost Gas recorded in the period	6,336
Reduction in Profit Gas in the period	(3,342)
Net impact on Company share of operating revenue	2,994

8 PERSONNEL EXPENSES

Personnel costs are as follows:

	YEARS ENDED 31 DECEMBER	
US$'000	**2015**	2014
Wages and salaries	**9,037**	8,958
Social security costs	**876**	675
Other statutory costs	**207**	321
	10,120	9,954
Stock based compensation	**(244)**	3,482
	9,876	13,436

Stock based compensation is recorded under general and administrative expenses in the statement of comprehensive income (loss). The balance of personnel expenses for 2015 of US$10.1 million (2014: US$10.0 million) is recorded in distribution and production expenses and general administrative expenses at US$1.9 million (2014: US$3.0 million) and US$8.0 million (2014: US$7.0 million) respectively.

9 NET FINANCE EXPENSE

US$'000	YEARS ENDED 31 DECEMBER 2015	2014
Finance income	**43**	98
Interest expense	**(117)**	(24)
Net foreign exchange loss	**(2,677)**	(4,437)
Financing fee	**(16)**	–
Provision for doubtful accounts	**(11,178)**	(37,047)
Finance expense	**(13,988)**	(41,508)
Net finance expense	**(13,945)**	(41,410)

During 2015, the Company billed TANESCO US$2.4 million (2014: US$2.2 million) of interest for late payments. The interest income is not recorded in the financial statements because it does not meet the revenue recognition criteria with respect to assurance of collectability. The Company is pursuing collection and amounts will be recognised in earnings when collected. The provision for doubtful accounts includes US$9.9 million (2014: US$35.1 million) for overdue TANESCO receivables and US$1.3 million (2014: US$1.9 million) relates to Songas receivables.

Total amount of interest paid in 2015 was nil (2014: US$17 thousand).

10 INCOME TAXES

The tax charge is as follows:

	YEARS ENDED 31 DECEMBER	
US$'000	**2015**	2014
Current tax	**7,691**	11,895
Deferred tax expense (recovery)	**1,705**	(457)
	9,396	11,438

Tax of US$3.0 million (2014: US$1.5 million) was paid during the year in relation to the settlement of the prior year's tax liability. The Company paid a further US$3.5 million related to periods from 2005 to 2013. In addition, provisional tax payments totaling US$6.9 million (2014: US$8.8 million) were made in respect of the current year. These are presented as a reduction in tax payable on the statement of financial position.

Tax rate reconciliation

	YEARS ENDED 31 DECEMBER	
US$'000	**2015**	2014
Income (loss) before tax	**10,929**	(26,863)
Provision for income tax calculated at the statutory rate of 30%	**3,279**	(8,059)
Add the tax effect of non-deductible income tax items:		
Administrative and operating expenses	**1,552**	1,387
Foreign exchange loss	**199**	349
Tax penalties	**–**	272
Stock-based compensation (recovery)	**(73)**	1,045
TANESCO interest not recognized as interest income (Note 9)	**714**	650
Unrecognized tax asset	**2,930**	15,646
Other permanent differences	**795**	148
	9,396	11,438

As at 31 December 2015, the provision for doubtful debt from TANESCO has resulted in a US$17.6 million (2014: US$15.6 million) unrecognised deferred tax asset. If this amount was ultimately not recovered, the Company would also be entitled to a US$10.5 million recovery of Value Added Tax.

A deferred tax asset of US$2.2 million (2014: US$2.2 million) in respect of Longastrino Italy exploration and evaluation costs has not been recognised because it is not probable that there will be future profits against which this can be utilised.

The deferred income tax liability includes the following temporary differences:

	AS AT 31 DECEMBER	
US$'000	**2015**	2014
Differences between tax base and carrying value of property, plant and equipment	**(18,185)**	(15,498)
Tax recoverable from TPDC	**(3,442)**	(5,116)
Provision for doubtful debt	**2,987**	2,945
Deferred Additional Profits Tax	**9,394**	8,688
Unrealised exchange losses/other provisions	**(66)**	1,375
	(9,312)	(7,606)

Tax recoverable

The Company has a tax recoverable balance of US$4.5 million (2014: US$11.8 million). This arises from the revenue sharing mechanism within the PSA, which entitles the Company to recover from TPDC, by way of a deduction from TPDC's Profit Gas share an amount equal to the actual income taxes payable by the Company. The recovery, by deduction from TPDC's share of revenue, is dependent upon payment of income taxes relating to prior period adjustment factors as they are assessed.

	AS AT 31 DECEMBER	
US$'000	**2015**	2014
Tax recoverable	**4,519**	11,815

Notes to the Consolidated Financial Statements

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 deferred APT by forecasting the total APT payable as a proportion of the forecast Profit Gas over the term of the PSA. The effective APT rate of 20.2% (2014: 21.9%) has been applied to Profit Gas of US$11.6 million (2014: US$37.4 million). Accordingly, US$2.4 million (2014: US$7.3 million) has been netted off revenue for the year ended 31 December 2015. The APT charge for the 2014 includes a reduction of US$0.9 million, reflecting the impact of recovering downstream costs on cumulative Profit Gas, as a result of the US$3.3 million Profit Gas adjustment identified in the Cost Pool adjustment (see Note 7).

12 TRADE AND OTHER RECEIVABLES

Current receivables	AS AT 31 DECEMBER	
US$'000	**2015**	2014
Trade receivables		
TANESCO	**7,831**	7,671
Songas	**2,178**	23,864
Industrial customers	**6,894**	7,532
	16,903	39,067
Other receivables		
Songas gas plant operations	**5,631**	19,300
Songas well workover programme	**11,209**	–
Other	**1,604**	773
Less provision for doubtful accounts	**(9,956)**	(9,816)
	8,488	10,257
	25,391	49,324

Trade receivables aged analysis

	AS AT 31 DECEMBER 2015				
US$'000	Current	>30 <60	>60 <90	>90	Total
TANESCO	3,972	3,859	–	–	7,831
Songas	1,082	1,096	–	–	2,178
Industrial customers	3,317	1,859	897	821	6,894
	8,371	6,814	897	821	16,903

	AS AT 31 DECEMBER 2014				
US$'000	Current	>30 <60	>60 <90	>90	Total
TANESCO	3,893	3,778	–	–	7,671
Songas	1,107	1,067	1,135	20,555	23,864
Industrial customers	3,469	2,758	810	495	7,532
	8,469	7,603	1,945	21,050	39,067

TANESCO

At 31 December 2015, TANESCO owed the Company US$69.7 million excluding interest (of which arrears were US$61.9 million) compared to US$59.8 million (including arrears of US$52.2 million) as at 31 December 2014. During the year, the Company received a total of US$34.1 million (2014: US$46.7 million) from TANESCO against sales totaling US$43.6 million (2014: US$54.7 million). Current TANESCO receivables as at 31 December 2015 amounted to US$7.8 million (2014: US$7.7 million). Since the year-end, TANESCO has paid the Company US$4.1 million in 2016, and as at the date of this report the total TANESCO receivable is US$75.4 million (of which US$61.9 million has been provided for). The amounts owed do not include interest billed to TANESCO.

The Company has reached an understanding with TANESCO that it would only continue to supply gas if TANESCO remained reasonably current with payments for current gas deliveries. Excess payments received over and above the current balances would be applied to the arrears balance. TANESCO payments for 2015 continued to be irregular but were sufficient to cover current gas deliveries until the third quarter when payments again were not sufficient to cover current gas deliveries. During Q4 2015 TANESCO payments further decreased with only US$4.5 million being received against sales of US$11.7 million. Management has reviewed the current position with TANESCO and concluded that the policy to reclassify all amounts receivable from TANESCO in excess of 60 days, and in arrears, as a long-term receivable is still appropriate. As a result, the Company has classified US$9.8 million, the arrears in excess of 60 days, as long-term and has placed a full provision against this amount. The current total provision is US$61.9 million (2014: US$ 52.2 million).

Long-term receivables	**AS AT 31 DECEMBER**	
US$'000	**2015**	2014
TANESCO receivable	**61,922**	52,154
Provision for doubtful debts	**(61,922)**	(52,154)
Net TANESCO receivable	**–**	–
VAT bond	**332**	369
Lease deposit	**252**	265
Long-term receivables	**584**	634

Songas

As at 31 December 2015, Songas owed the Company US$19.0 million (2014: US$43.2 million), whilst the Company owed Songas US$2.6 million (2014: US$30.4 million); there is no contractual right to offset these amounts. Amounts due to Songas primarily relate to pipeline tariff charges of US$ 1.1 million (2014: US$28.9 million), whereas the amounts due to the Company are mainly for capital expenditures of US$11.2 million (2014: US$nil), sales of gas of US$2.2 million (2014: US$23.9 million) and for the operation of the gas plant of US$5.6 million (2014: US$19.3 million). The operation of the gas plant is conducted at cost and the charges are billed to Songas on a flow through basis.

As at 31 December 2015 the net amount owed by Songas to the Company was US$16.3 million (2014: US$12.7 million). Although significant progress has been made in settling outstanding balances, a doubtful debt provision of US$9.8 million is necessary recognizing the pending settlement of the remaining overdue operatorship charges and the Songas share of the well workover costs. Any significant amounts not agreed will likely be pursued through the mechanisms provided in the agreements with Songas.

All amounts due to and from Songas have been summarized in the net Songas balance (see Note 15).

13 PROPERTY, PLANT AND EQUIPMENT

US$'000	Oil & natural gas interests	Leasehold improvements	Computer equipment	Vehicles	Fixtures & fittings	Total
Costs						
As at 1 January 2015	140,653	699	1,233	149	1,125	143,859
Additions	38,155	–	108	148	–	38,411
As at 31 December 2015	178,808	699	1,341	297	1,125	182,270
Accumulated depletion and depreciation						
As at 1 January 2014	63,534	170	955	120	662	65,441
Depletion and depreciation	11,855	175	213	48	264	12,555
As at 31 December 2015	75,389	345	1,168	168	926	77,996
Net book values						
As at 31 December 2015	103,419	354	173	129	199	104,274

US$'000	Oil & natural gas interests	Leasehold improvements	Computer equipment	Vehicles	Fixtures & fittings	Total
Costs						
As at 1 January 2014	139,072	885	1,158	137	1,082	142,334
Additions	1,103	72	75	12	50	1,312
Transfer from Exploration & Evaluation assets	478	–	–	–	–	478
Disposals	–	(258)	–	–	(7)	(265)
As at 31 December 2014	140,653	699	1,233	149	1,125	143,859
Accumulated depletion and depreciation						
As at 1 January 2014	49,967	245	761	137	392	51,502
Depletion and depreciation	13,567	183	194	(17)	270	14,197
Disposals	–	(258)	–	–	–	(258)
As at 31 December 2014	63,534	170	955	120	662	65,441
Net book values						
As at 31 December 2014	77,119	529	278	29	463	78,418

In determining the depletion charge, it is estimated that future development costs of US$103.8 million (2014: US$252 million) will be required to bring the total proved reserves to production. The decrease in estimated future development costs is a result of the successful workovers completed during the year. This reduced the amount of capital expenditure required in the future to ensure the Company can produce the required gas volumes to meet its contractual obligations for the remaining life of the license. During the year the Company recorded depreciation of US$0.7 million (2014: US$0.6 million) in general and administrative expenses.

14

ASSET IMPAIRMENT

During 2014, site costs of survey and materials purchased in preparation for the drilling of the first Songo Songo West well of US$5.1 million recorded in exploration and evaluation assets were identified as having been impaired.

15

TRADE AND OTHER PAYABLES

US$'000	AS AT 31 DECEMBER **2015**	2014
Songas [1]	**1,071**	28,871
Other trade payables	**11,234**	1,961
Trade payables	**12,305**	30,832
TPDC share of Profit Gas	**28,208**	33,409
Deferred income	**667**	2,780
Accrued liabilities	**8,351**	9,726
	49,531	76,747

(1) A summary of all Songas balances is presented below, including the opening position, movements during the year and details of post year-end settlements made in cash by the Company and by Songas (see Note 12).

	1 January 2015	**Year to date transactions**	**Gross balance 31 Dec 2015**	**Post year-end payments and receipts**	**Outstanding as at the date of this report**
Pipeline tariff – payable	(28,871)	27,800	(1,071)	1,071	–
Gas sales – receivable	23,864	(21,686)	2,178	(2,178)	–
Gas plant operation receivable	19,300	(13,669)	5,631	–	5,631
Workover programme	–	11,209	11,209	–	11,209
Other payable	(1,574)	28	(1,546)	–	(1,546)
Net balances	12,719	3,682	16,401	(1,107)	15,294

Notes to the Consolidated Financial Statements

16 LONG-TERM LOAN

On the 29th October 2015, the Company entered into a loan agreement ("Loan") with the International Finance Corporation ("IFC"), a member of the World Bank Group, for a US$60 million investment in the Company's operating subsidiary, PanAfrican Energy Tanzania Limited ("PAET").

The term of the Loan is 10-years, with no repayment of principal for the first seven years, followed by a three-year amortization period. The Loan is an unsecured subordinated obligation of PAET and is guaranteed by the Company to a maximum of US$30 million. The guarantee may only be called upon by IFC at maturity in 2025 and, subject to IFC approval and receipt of all required regulatory approvals, the Company may issue shares in fulfillment of all or part of the guarantee obligation in 2025.

Base interest on the Loan is payable quarterly at 10% per annum on a 'pay-if-you-can-basis' using a formula to calculate the net cash available for such payments as at any given interest payment date. In addition, an annual variable participatory interest equating to 7% of the cash flow of PAET net of capital expenditures is payable in respect of any given year, commencing with 2016. Such participatory interest will continue until 15 October 2026 regardless whether the Loan is repaid prior to its contractual maturity date. Dividends and distributions from PAET to the Company are restricted during the term of the Off-Shore Programme and at any time that any amounts of unpaid interest, principal or participating interest are outstanding. The Off-Shore Programme was completed subsequent to year-end.

On the 14th December 2015, PAET made an initial drawdown of US$20 million from the available US$60 million. Subsequent to the year-end PAET has drawn the remaining US$40 million.

	AS AT 31 DECEMBER	
US$'000	**2015**	2014
Total IFC facility	**60,000**	–
Loan drawdown	**20,000**	–
Financing costs	**(1,401)**	–
	18,599	–

17 CAPITAL STOCK

A. 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.

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

Number of shares	2015			2014		
	Authorised (000)	Issued (000)	Amount (US$'000)	Authorised (000)	Issued (000)	Amount (US$'000)
Class A						
As at 1 January and 31 December	**50,000**	**1,751**	**983**	50,000	1,751	983
Class B						
As at 1st January	**100,000**	**33,164**	**84,654**	100,000	33,072	84,445
Stock options exercised	**–**	**–**	**–**	–	92	209
Normal course issuer bid repurchases	**–**	**(58)**	**(149)**	–	–	–
As at 31 December	**100,000**	**33,106**	**84,505**	100,000	33,164	84,654
First preference						
As at 31 December	**100,000**	**–**	**–**	100,000	–	–
Total Class A, Class B and first preference	**250,000**	**34,857**	**85,488**	250,000	34,915	85,637

All of the issued capital stock is fully paid.

Stock Options	2015 Options	2015 Exercise Price	2014 Options	2014 Exercise Price
Number of options	***(000)***	***CDN$***	*(000)*	*CDN$*
Outstanding as at 1 January	**400**	**3.18**	1,742	1.00 to 3.60
Forfeited	**(400)**	**3.18**	(250)	3.60
Exercised	**–**	**–**	(92)	1.00
Expired unexercised	**–**	**–**	(1,000)	1.00
Outstanding as at 31 December	**–**	**–**	400	3.18

Notes to the Consolidated Financial Statements

Stock Appreciation Rights ("SARs")	2015 SARs	2015 Exercise Price	2014 SARs	2014 Exercise Price
Number of options	***(000)***	***(CDN$)***	*(000)*	*(CDN$)*
Outstanding as at 1 January	**2,910**	**2.12 to 4.20**	1,130	2.12 to 4.20
Expired	**(300)**	**4.20**	–	–
Granted [(i)]	**490**	**3.02 to 3.25**	1,780	2.30
Outstanding as at 31 December	**3,100**	**2.12 to 3.25**	2,910	2.12 to 4.20

(i) A total of 490,000 SARs were issued during the year with an exercise price from CDN$3.02 to CDN$3.25. These rights have a term of one to five years and vest in equal annual instalments, the first tranche vesting on the anniversary of the grant date. There is no maximum liability associated with these rights.

The weighted average remaining life and weighted average exercise prices of SARs at 31 December 2015 were as follows:

Exercise price *(CDN$)*	Number outstanding as at 31 December *(000)*	Weighted average remaining contractual life *(years)*	Number exercisable as at 31 December 2015 *(000)*	Weighted average exercise price *(CDN$)*
2.12 to 2.30	2,080	2.96	556	2.27
2.35 to 2.70	530	1.86	530	2.48
3.02 to 3.25	490	4.79	–	3.06
2.12 to 3.25	3,100	3.06	1,086	2.43

Restricted Stock Units ("RSUs")	2015 RSUs *(000)*	2015 Grant/exercise price *(CDN$)*	2014 RSUs *(000)*	2014 Grant/exercise price *(CDN$)*
Outstanding as at 1 January	**645**		–	–
Granted	**–**	**–**	792	3.70
Exercised	**(645)**		(147)	3.79
Outstanding as at 31 December	**–**	**–**	645	2.90

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 1.5%, stock volatility of 48.9% to 51.6%; 0% dividend yield; 5% forfeiture; a closing stock price of CDN$2.75 per share.

US$'000	YEAR ENDED 31 DECEMBER 2015	2014
SARs	**1,572**	1,766
RSUs	**–**	1,613
	1,572	3,379

As at 31 December 2015, a total accrued liability of US$1.6 million (2014: US$3.4 million) has been recognised in relation to SARs and RSUs which is included in other payables. The Company recognised a credit for the year of US$0.2 million (2014: expense US$3.5 million) in general and administrative expenses.

The credit in 2015 was the result of a 5% reduction in the share price to US$2.75 (2014: US$2.90) and a net increase in SARs of 190,000. The 2014 charge reflected the issue of 792,000 RSUs and 1,780,000 SARs.

18 EARNINGS PER SHARE

('000)	AS AT 31 DECEMBER 2015	2014
Outstanding shares		
Weighted average number of Class A and Class B shares	**34,887**	34,863
Weighted average diluted number of Class A and Class B shares	**34,887**	34,863

The calculation of basic earnings (loss) per share is based on a net income (loss) for the year of US$1.5 million (2014: loss US$38.3 million) and a weighted average number of Class A and Class B shares outstanding during the period of 34,887,100 (2014: 34,862,588).

19 RELATED PARTY TRANSACTIONS

One of the non-executive Directors is a partner at a law firm that provides legal advice to the Company and its subsidiaries. For the year ended 31 December 2015 US$0.6 million (2014: US$0.2 million) was incurred from this firm for services provided. The transactions with this related party were made at the exchange amount.

The former Chief Financial Officer who became an Executive Vice-President in November 2015, provided services to the Company through a consulting agreement with a personal services company. For the year ended 31 December 2015 US$0.4 million (2014: US$0.6 million) was incurred from this firm for services provided.

As at 31 December 2015 the Company has a total of US$0.4 million (2014: US$nil) recorded in trade and other payables in relation to the related parties.

20 CONTRACTUAL OBLIGATIONS & COMMITTED CAPITAL INVESTMENTS

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, then the Company is liable to pay the difference between the price of Protected Gas (US$0.55/MMbtu escalated) and the price of an alternative feedstock multiplied by the volumes of Protected Gas up to a maximum of the volume of Additional Gas sold (145.0 Bcf as at 31 December 2015). 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.

The Gas Agreement may be superseded by an initialed Amended and Restated Gas Agreement ("ARGA"). The unsigned ARGA provides clarification of the Protected Gas volumes and removes all terms dealing with the security of the Protected Gas and contract terms dealing with the consequences of any insufficiency are dealt with in a new Insufficiency Agreement ("IA"). The IA specifies terms under which Songas may demand cash security in order to keep it whole in the event of a Protected Gas insufficiency. Should the IA be signed, it will govern the basis for determining security. Under the provisional terms of the IA, when it is calculated that funding is required, the Company is required to fund an escrow account at a rate of US$2.00/MMbtu on all Industrial Additional Gas sales out of its and TPDC's share of revenue, and TANESCO shall contribute the same amount on Additional Gas sales to the Power sector. The funds provide security for Songas in the event of an insufficiency of Protected Gas. The Company is actively monitoring the reservoir and, supported by the report of its independent engineers, does not anticipate that a liability will occur in this respect. As at the date of this report, the ARGA remains an initialed agreement only, however the parties thereto, in certain respects, are conducting themselves as though the ARGA is in full force and effect.

Re-Rating Agreement

In 2011, the Company signed a re-rating agreement with TANESCO and Songas (the "Re-rating Agreement") to increase the gas processing capacity 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 effectively pays an additional tariff of US$0.30/mcf for sales between 70 MMcfd and 90 MMcfd and US$0.40/mcf for volumes above 90 MMcfd in addition to the tariff of US$0.59/mcf payable to Songas as set by the energy regulator, EWURA. The Re-rating agreement expired on 31 December 2013. Since 31 December 2013 production has continued within the higher rated limit and the Company expects this to continue. However, there are no assurances that the ability to produce at the higher rating will continue.

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

Portfolio Gas Supply Agreement ("PGSA")

On 17 June 2011, a long term (to June 2023) PGSA was signed between TANESCO (as the buyer) and the Company and TPDC (collectively as the seller). Under the PGSA, the seller is obligated, subject to infrastructure capacity, to sell a maximum of approximately 37 MMcfd for use in any of TANESCO's current power plants except those operated by Songas at Ubungo. Under the agreement, the basic wellhead price of approximately US$2.93/mcf increased to US$2.98/mcf on 1 July 2015. Any volumes of gas delivered under the PGSA in excess of 36 MMcfd are subject to a 150% increase in the basic wellhead gas price.

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 1 November 2015 and expires on 31 October 2019 at an annual rent of US$0.4 million. The agreement in Winchester expires on 25 September 2022 and is at an annual rental of US$0.1 million per annum. The costs of these leases are recognised in the general and administrative expenses.

Capital Commitments

Italy

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

Tanzania

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

Given the completion of the Offshore component of Phase I of the Development Programme in February 2016, which has improved field deliverability and provides sufficient natural gas production to fill the Songas plant and pipeline to capacity for the greater portion of the remaining life of the production license, the Company does not expect to commit to further significant capital expenditures until: (i) agreeing commercial terms with TPDC for the supply of gas to the NNGIP regarding the sale of incremental gas volumes from Songo Songo; and/or (ii) TANESCO arrears have been substantially reduced, guaranteed or other arrangements for payment made that are satisfactory to the Company; and/or (iii) the establishment of payment guarantees with the World Bank or other multi-lateral lending agencies to secure future receipts under any new sales contracts with Government entities.

When the required conditions are met, and in so doing justify further improving the reliability/capacity of field deliverability, the Company would contemplate undertaking the remaining part of the Phase I Development Programme. The additional costs are estimated to be approximately US$30 million. There is no assurance that financing will be available and on acceptable commercial terms to complete Phase I.

21 CONTINGENCIES

Downstream unbundling

The newly passed Petroleum Act, 2015 (the "Act") was passed into Law by Presidential decree on 4 August 2015. In relation to the unbundling of the downstream business, the Act vests TPDC with exclusive rights in the distribution of gas, however, the Act has a provision which recognizes the Company's PSA within the legislation. The Company does not expect the new legislation to have a significant impact on the downstream distribution business however it is still unclear how the provisions of the Act will be interpreted and implemented.

TPDC Back-in

TPDC has previously indicated a wish to exercise its right under the PSA to 'back in' to the Songo Songo field development and a further wish 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.

For the purpose of the reserves certification as at 31 December 2015, it was assumed that TPDC will elect to 'back-in' for 20% for all future new drilling activities within the prescribed period as determined by the current development plan and this is reflected in the Company's net reserve position.

Cost recovery

TPDC conducted an audit of the historic Cost Pool and in 2011 disputed approximately US$34 million of costs that had been recovered from the Cost Pool from 2002 through to 2009. In 2014 TPDC and the Company agreed to remove US$1.0 million from the Cost Pool. In 2015 there have been no further developments. 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, as at the time of writing this report no such specialist has been appointed. If the matter is not resolved to the Company's satisfaction, the Company intends to proceed to arbitration via the International Centre for Settlement of Investment Disputes ("ICSID") pursuant to the terms of the PSA.

Taxation

Area	Period	Tax dispute Reason for dispute	Disputed amount US$ million Principal	Interest	Total
PAYE	2008-10	Pay-As-You-Earn ("PAYE") withholding tax on taxable income of employees on grossed up equivalent of staff salaries, which are contractually stated as net.	0.3	–	0.3 (1)
WHT	2005-10	WHT on services by non-resident persons performed outside of Tanzania.	1.1	0.8	1.9 (2)
Income Tax	2008-13	Deductibility of capital expenditures and expenses (2009), additional income tax (2008, 2010, 2011), and foreign exchange rate application (2013).	5.2	1.4	6.6 (3)
VAT	2008-10	Output VAT on imported services and SSI Operatorship services.	2.8	3.0	5.8 (4)
			9.4	5.2	14.6

(1) During the year, PAET appealed the Tax Revenue Appeals Board ("TRAB") ruling that PAET is liable to pay PAYE on grossed up equivalent of staff salaries. PAET is awaiting appeal date to be set up with the Tax Revenue Appeals Tribunal ("TRAT");

(2) 2005-2009 (US$1.8 million): During the year, TRAT ruled in favor of PAET. TRA has filed notice of appeal with the Court of Appeal, and PAET is awaiting decision of the Court of Appeal.

2010 (US$0.1 million): TRAB is awaiting a ruling from the Court of Appeal on the 2005-2009 case, which would influence TRAB decision on this matter accordingly.

(3) (a) 2009 (US$1.8 million): During the year, TRAB has ruled against PAET with respect to the deductibility of capital expenditures and expenses. PAET appealed to TRAT and is awaiting hearing date to be scheduled;

(b) 2008, 2010-2011 (US$4.6 million): During the year, PAET filed objections against TRA assessments with respect to additional tax and is awaiting a response;

(c) 2013 (US$ 0.2 million): During the year, PAET filed objections to TRA assessment with respect to foreign exchange rate application and is awaiting a response.

(4) In 2014, PAET filed an objection to TRA's claims and is awaiting a response.

Management, with the advice from its legal counsels, has reviewed the Company's position on the above objections and appeals and has concluded that no provision is required with regard to the above matters.

Notes to the Consolidated Financial Statements

22 DIRECTORS AND OFFICERS EMOLUMENTS

US$'000	Year	Base	Bonus	Stock based compensation expense	Total
Directors	2015	1,100	500	1,676	3,276
Directors	2014	1,412	660	2,412	4,484
Officers	2015	1,469	345	43	1,857
Officers	2014	748	210	334	1,292

The table above provides information on compensation relating to the Company's officers and directors. Six officers and three non-executive directors comprised the key management personnel during the year ended 31 December 2015 (2014: four officers and two non-executive directors). One of the officers is also a director and as such their remuneration has been included under directors' emoluments in the table above.

Corporate Information

Board of Directors

W. David Lyons
Chairman and
Chief Executive Officer

Queensway
Gibraltar

David W. Ross
Non-Executive Director

Calgary, Alberta
Canada

William H. Smith
Non-Executive Director

Calgary, Alberta
Canada

Glenn D. Gradeen
Non-Executive Director

Calgary, Alberta
Canada

Officers

W. David Lyons
Chairman and
Chief Executive Officer

Queensway
Gibraltar

Blaine Karst
Chief Financial Officer

Calgary, Alberta
Canada

Stephen Huckerby
Chief Accounting Officer

St. Peters, Jersey
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